ASIA PACIFIC ENERGY RESEARCH CENTRE

APEC ENERGY OVERVIEW

2002

DECEMBER - 2002

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FOREWORD

The APEC region continues facing many challenges in providing for the energy needs of its growing economies. Energy transport infrastructure – which allows energy to be obtained from a variety of sources in a variety of forms – is increasingly recognised as vital to ensuring the security of energy supply and competition among energy suppliers. Reform of gas and electricity markets continues to be pursued as a means of enhancing productive efficiency and reducing energy prices to consumers. Energy efficiency measures are being promoted as a cost-effective and environmentally beneficial adjunct to supply-side options for providing energy services. As always, providing adequate supplies of oil, gas and electricity in an environmentally responsible manner and at reasonable cost is essential to sustainable economic growth in the region.

Recognising the importance of information exchange on recent energy trends, the APEC Expert Group on Energy Data and Analysis (EGEDA) and the APEC Energy Working Group (EWG) endorsed the production of an annual *APEC Energy Overview* at their meetings in early 2000. It was agreed that the Asia Pacific Energy Research Centre (APERC) would coordinate the work every year in cooperation with EGEDA. The goal of the *APEC Energy Overview* is to put current energy issues in context by providing a concise summary of the energy situation and policy directions of each member economy.

In preparing the *Overview*, APERC researchers have had the benefit of information from a wide variety of public sources which are noted as references to the reports on each of the member economies. We would like to acknowledge in particular the efforts of APEC member economies in ensuring the currency and reliability of information provided.

To ensure a consistent picture across the 21 APEC economies, per instructions from EGEDA and EWG, the *Overview* uses macroeconomic and energy data provided by the Energy Data and Modelling Center (EDMC) of the Institute of Energy Economics, Japan. We would like to express our appreciation for the EDMC's efforts in providing this data.

Finally, we would like to thank APERC researchers for their contributions to this report and note our gratitude for the guidance extended by EGEDA members in compiling it.

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December 2002

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LIST OF ABBREVIATIONS

ABARE	Australian Bureau of Agriculture and Resource Economics
APEC	Asia Pacific Economic Cooperation
APERC	Asia Pacific Energy Research Centre
ASEAN	Association of Southeast Asian Nations
AUS	Australia
bbl/d	Barrels per day
BCM	Billion cubic metres
BD	Brunei Darussalam
Bt	Billion tonnes (Thousand Mt)
CDA	Canada
CHL	Chile
CO_2	Carbon dioxide
CT	Chinese Taipei
EDMC	Energy Data and Modelling Center (Japan)
EIA	Energy Information Administration (USA)
EWG	Energy Working Group (APEC)
GDP	Gross domestic product
GHG	Greenhouse gases
GW	Gigawatts (Thousand MW or Million kW)
GWh	Gigawatt-hours (Million kWh)
HKC	Hong Kong, China
IPP	Independent Power Producer
INA	Indonesia
JPN	Japan
ktoe	Kilotonnes (thousand tonnes) of oil equivalent
kW	Kilowatts
kWh	Kilowatt-hour
LNG	Liquefied natural gas
LPG	Liquefied petroleum gas (propane)
MAS	Malaysia
MCM	Million cubic metres
MEX	Mexico
Mt	Megatonnes (Million tonnes)
MW	Megawatts (Thousand kW)
NZ	New Zealand
PE	Peru
PNG	Papua New Guinea (or pipeline natural gas, depending on context)
PPP	Purchasing Power Parity
PRC	People's Republic of China
R&D	Research and development
RMB	Renminbi, currency of China (yuan)
ROK	Republic of Korea
RP	The Republic of the Philippines
RUS	The Russian Federation
SIN	Singapore
SDPC	State Development and Planning Commission (China)
TFEC	Total final energy consumption
TPES	Total primary energy supply
toe	Tonnes of oil equivalent
TWh	Terawatt-hours (Billion kWh)
US or USA	United States of America
VN	Viet Nam

AUSTRALIA

INTRODUCTION

The Australian continent covers approximately 7.6 million square kilometres with a total population of 19.2 million. The majority of the population is located along the eastern seaboard, mainly in cities or major regional centres. Australia has a wide range of mineral and energy resources.

In the decade to 2000, economic growth in Australia was quite robust at about 3.7 percent per annum. In 2000, GDP was US$ 477 billion (1995 US$ at PPP) and the unemployment rate was around 6.9 percent. The Australian economy has remained relatively robust through the global economic slowdown of the last few years, has avoided recession, and is expected to outperform most developed economies in 2003.

Australia is a major exporter of coal, LNG and uranium. The resource sector is the largest exporting sector of the Australian economy, comprising over 35 percent of its export earnings. Consequently, the economy is sensitive to changes in foreign earnings arising from fluctuations in resource prices on international markets.

Table 1 Key data and economic profile (2000)

Key data		Energy reserves*	
Area (sq. km)	7,600,000	Oil	461 MCM
Population (million)	19.18	Gas	1,260 BCM
GDP Billion US$ (1995 US$ at PPP)	476.68	Coal	90.4 Bt
GDP per capita (1995 US$ at PPP)	24,851		

Source: Energy Data and Modelling Center, IEEJ.

* Proved reserves, end of 2000, BP Statistical Review.

ENERGY SUPPLY AND DEMAND

PRIMARY ENERGY SUPPLY

In 2000, the total primary energy supply in Australia was 110,841 ktoe. Of this total, 32 percent was oil, 43 percent coal, and 18 percent natural gas.

Australia is the world's largest exporter of coal, and total indigenous production in 2000 was 168,199 ktoe (318.1 million tonnes). 120,129 ktoe (71 percent) of this was exported. Much of the coal consumed domestically is used for power generation (Australia relies on coal for around 80 percent of generation), with most of the balance being used in the production of energy intensive commodities – particularly iron and steel and aluminium. World coal demand has continued to grow strongly. Spot market prices for steam coal increased from the low US$ 20s in 2000 per tonne to the low US$ 30s in 2001with settlements in the mid-US$ 30s in mid-2002. Responding to firmer prices and increased coal demand in Asia, Australian coal producers have raised production levels. A number of planned projects were commissioned during 2001, which together have the potential to add as much as 11.5 million tonnes of capacity.

In 2000, Australia had 1,260 BCM of natural gas reserves, up from 440 BCM in 1990. Natural gas production in 2000 was 28,293 ktoe. Of this, 8,805 ktoe was exported as liquefied natural gas (LNG) to markets in Asia and Europe. At 2000 production levels this amounts to around 40 years of reserves. The biggest market by far for Australian LNG is Japan. Australia began exporting

LNG to the Asia Pacific region at the end of the 1980s. These exports initially grew rapidly but levelled out after the 1997 Asian financial crisis.

In 2000, Australia produced 31,744 ktoe of crude oil and condensates. Although Australia exports some crude oil, total demand exceeds indigenous production, so Australia is a net importer of oil and petroleum products. Oil reserves in 2000 stood at 2,900 million barrels, up from 1,600 million barrels in 1990. The reserve-to-production ratio is around 9.8 years.

Australia produced 203,151 GWh of electricity in 2000. Production was mostly from thermal sources (91 percent) with a small amount from hydro (8 percent). Of thermal fuel consumption, almost all was from coal (94 percent) with the balance from gas and oil. Electricity demand growth has been quite robust during the last decade, increasing by about 2.8 percent per annum.

Table 2 Energy supply & consumption (2000)

Total Primary Energy Supply	**(ktoe)**	**Total Final Energy Consumption**	**(ktoe)**	**Power Generation**	**(GWh)**
Indigenous Production	236,051	Industry Sector	28,776	Total	203,151
Net Imports & Other	-125,210	Transport Sector	26,758	Thermal	184,239
TPES	110,841	Other Sectors	17,858	Hydro	17,137
Coal	48,057	TFEC	73,393	Nuclear	0
Oil	35,482	Coal	3,845	Others	1,775
Gas	19,488	Oil	35,227		
Others	7,814	Gas	14,226		
		Electricity & Others	20,096		

Source: Energy Data and Modelling Center, IEEJ (see http://www.ieej.or.jp/apec/database/selecttable.html)

FINAL ENERGY CONSUMPTION

In 2000, total end use energy consumption in Australia was 73,393ktoe. By sector, industry consumed 39 percent of energy, transport 36 percent, and other sectors (including residential and commercial) 24 percent. By fuel, petroleum products accounted for 48 percent of consumption, natural gas for 19 percent, coal for 5 percent and electricity for 27 percent. Between 1990 and 2000, consumption of natural gas grew at an annual rate of 3.1 percent. Impediments to more widespread use of gas include the large distances between main sources of supply in the far west and centres of demand on the eastern seaboard, as well as the very competitive price of steam coal for power generation. Despite this, it is expected that extensions of the natural gas pipeline network will continue to open up large markets, particularly in the mining, manufacturing and electricity generation sectors. This should result in domestic natural gas demand growth accelerating to around 3.5 percent per annum over the next decade or two.

POLICY OVERVIEW

The Australian government is working to develop energy policies that recognise cross-sectoral linkages, promote a structure that maximises the economic and social potential of energy industries, help reduce the environmental impacts of energy use. A key issue for the Australian government is ensuring that all key stakeholders, including industry, the Commonwealth and states/territories, are in agreement on key energy policy objectives and their linkages to broader national goals. In recent years, federal government reforms have focused on the development of a transparent, free and competitive energy market.

NATIONAL ENERGY MARKET REFORM

Market-based reforms undertaken in the Australian electricity and gas sectors in recent years have already delivered considerable benefits to the national economy. In June 2001, Australian Governments reaffirmed earlier agreed energy market reform objectives and committed themselves to the continuous improvement of Australia's national energy markets. Significant progress has been made in taking forward the renewed program of reforms in the last twelve months.

The Council of Australian Governments (CoAG) has established an energy policy framework that includes (i) a Ministerial Council on Energy (MCE), (ii) an Independent Review of Energy Market Directions, and (iii) a National Electricity Market (NEM) Ministers Forum.

(I) MINISTERIAL COUNCIL ON ENERGY

Key priorities being addressed by the MCE are:

- Existing and potential gas and electricity market regulatory structures and institutional mechanisms, including the extent to which they facilitate an efficient and competitive energy sector with adequate investment and benefits to users;
- The potential harmonisation of regulatory arrangements, removing inconsistencies and integrating networks;
- Opportunities for and impediments to increasing interconnection and system security in gas and electricity;
- Ways of accelerating the delivery of improved customer choice; and
- Identifying opportunities for encouraging the wider penetration of natural gas.

Issues being addressed include the merits of a single national energy regulator, consistent with increasing convergence of the gas and electricity markets.

(II) INDEPENDENT REVIEW OF ENERGY MARKET DIRECTIONS

The independent review of energy market directions is working to identify the long term strategic issues affecting the Australian energy markets and the policies required from Commonwealth, State and Territory Governments to address them. The review team's final report was due in December 2002. The agreed terms of reference include:

- Identifying any impediments to the full realisation of the benefits of energy market reform;
- Identifying strategic directions for further energy market reform;
- Examining regulatory approaches that effectively balance incentives for new supply investment, demand responses and benefits to consumers;
- Assessing the potential for regions and small business to benefit from energy market development;
- Assessing the relative efficiency and cost effectiveness of options within the energy market to reduce greenhouse gas emissions from the electricity and gas sectors, including the feasibility of a phased introduction of a national system of greenhouse emission reduction benchmarks; and
- Identifying means of encouraging the wider penetration of natural gas including increased upstream gas competition, value adding processes for natural gas and potential other uses such as distributed generation, because it is an abundant, domestically available and clean energy resource.

(III) NATIONAL ELECTRICITY MARKET MINISTERS' FORUM

The NEM Ministers' Forum was established by NEM state energy ministers in 2001 and was tasked by the CoAG to progress the following priority issues:

- Impediments to investments in interconnections;
- Transmission pricing;
- Improved integration of transmission networks;
- Reducing regulatory overlay and institutional inefficiencies;
- Market behaviour (e.g. rebidding); and
- Demand side participation.

NATURAL GAS

In November 1997, Commonwealth, State and Territory governments signed the Natural Gas Pipeline Access Agreement. The agreement allows access to pipelines by third parties and will result in increased competition, a more integrated transmission and distribution network, and greater security of supply in the domestic gas market.

The Government launched the Liquefied Natural Gas (LNG) Action Agenda on 10 October 2000 to promote the international competitiveness of the Australian LNG industry. The LNG Action Agenda provides a framework of joint government and industry commitments for securing the future of the LNG industry. It addresses issues of greenhouse policy, customs and import tariffs, taxation arrangements, Australian industry participation, streamlined project approval processes, and marketing of LNG.

PETROLEUM PRODUCTS

In November 2002, the Minister for Industry, Tourism and Resources, the Hon Ian Macfarlane MP, launched the Downstream Petroleum Industry Framework. The Framework is an important first step in an ongoing dialogue between industry and government stakeholders to support and encourage change in the downstream petroleum sector. The Framework highlights critical issues as identified by small and large business associations, state, territory and commonwealth agencies, during an extensive consultation process.

URANIUM

In August 2000, amendments were made to the *Customs (Prohibited Exports) Regulations 1958* which control uranium exports. As a result of these changes, export permissions can now be issued for a specified period of time and can better incorporate appropriate safeguards and environmental requirements.

In 2002, the uranium mining industry has been subject to three separate Government reviews: the Bachmann Review conducted by the South Australian Government, the Lea review conducted by the Northern Territory Government, and a Commonwealth Senate Inquiry.

NOTABLE RECENT ENERGY DEVELOPMENTS

NATIONAL ENERGY POLICY

The National Electricity Code Administrator is currently moving forward with stages 1 and 2 of the *Review of the Scope for Integrating the Energy Market and Network Services* (the RIEMNS Review). This Review includes an evaluation of current regional boundaries and methods for calculating transmission loss factors, with a view to improving locational pricing signals within the NEM.

The corporatisation of the Snowy Mountains Hydro-electric Authority took place on 28 June 2002. The operation of the Snowy Mountains Scheme is now undertaken by Snowy Hydro Limited, a company owned by the Commonwealth, NSW and Victorian Governments. The Snowy Scheme is the largest supplier of renewable energy to the NEM.

As part of the 1994 objectives agreed by all Australian Governments to achieve free and fair trade in natural gas and remove barriers to interstate gas trade, the gas industry has been developing a national gas quality standard that it will publish shortly. All jurisdictions will then consider measures to implement the standard.

The responsibility for implementing timetables to achieve full retail contestability (FRC) for gas and electricity resides within each state and territory jurisdiction. While large to medium electricity and gas consumers are now fully contestable, timetables for achieving FRC in some states have been modified. The Commonwealth policy goal is for all States and Territories to adopt compatible approaches and avoid the establishment of barriers to competition within and between different regional markets.

Of the NEM states (Queensland, NSW, Victoria and South Australia), NSW and Victoria have achieved FRC while Queensland is not yet proceeding to full contestability. For gas, the largest consumer states, NSW and Victoria, have achieved FRC, with only South Australia and Western Australia (who will achieve it in 2003) part of the way there. Whether Queensland proceeds to FRC depends on the outcome of a cost benefit analysis to be conducted.

ELECTRICITY INTERCONNECTION AND GENERATION

A number of additional electricity interconnection proposals are currently being considered. If all the proposed links proceed the potential interconnected multi-state market will represent some 90 percent of total Australian electricity supply.

Queensland will add approximately 2500 MW of generation capacity by the end of 2002, including 500 MW that was earlier not expected to be commissioned until 2003. By the end of 2002, Victoria will have added around 660 MW, South Australia, 300 MW and New South Wales, 220 MW. Approximately 1000 MW of new capacity is proposed and committed to in 2003 in both Victoria and South Australia.

Four gas-fired power stations have been commissioned during 2002:

- Early in the year, the Australian Gas Light Company commissioned a 180 MW gas/oil dual-fired station at Hallett, South Australia, and Origin Energy started up their 98 MW gas-fired plant at Quarantine, South Australia.
- In February, Duke Energy doubled the capacity of the Bairnsdale, Victorian plant by commissioning a 43 MW gas turbine.
- In August, Edison Mission and Contact Energy commissioned a 2,094 MW gas peaking plant in the La Trobe Valley in Victoria.

GREENHOUSE GAS PROGRAMMES

The Government will continue to develop and fund domestic programs to meet the target Australia agreed to at Kyoto, whether or not the Protocol comes into force internationally. This commitment involves $1 billion over 5 years to implement a comprehensive package of greenhouse gas mitigation policies, meaning that on a per capita basis, Australia has spent as much as, if not more than, most other industrialised countries on climate change.

Australia has recently announced that it would not ratify the Kyoto Protocol at this time. It is the Australian Government's position that in meeting its greenhouse objectives, Australia is not prepared to sacrifice its industry's competitiveness and jobs, and that an effective global climate change agreement must involve all major emitters, including the United States and developing countries.

On 9 July 2002, the United States and Australian governments announced the first set of cooperative projects to be implemented under the Climate Action Partnership. The United States and Australia have established a total of nineteen cooperative projects under the Partnership. These projects cover Climate Science and Monitoring, Emission Accounting, Technology Development, Engaging Business, and Collaborating with Developing Countries**.** The United States and Australia consider that these projects will make a real contribution to reducing greenhouse gas emissions and to increasing the world's scientific understanding of climate change.

In August 2002 the Australian Government announced a climate change action agenda to ensure Australia continues to cut greenhouse emissions even further while building a strong, competitive economy. Four elements will underpin the development of Australia's forward climate change strategy:

- Australia will strive for a more comprehensive global response to climate change;
- Australia will position itself to maintain a strong and internationally competitive economy with a lower greenhouse signature;
- Domestic policy settings will balance flexibility with sufficient certainty to allow key decisions on investment and technology development, and also emphasise cost effectiveness; and
- Australia will implement policies and programs that assist adaptation to the consequences of the climate change that are already unavoidable.

GAS PIPELINE DEVELOPMENT

Some of the major gas pipeline developments proposed or under construction are described in the following:

- Construction of the A$400 million gas pipeline from Longford in Victoria to the Bell Bay region of northern Tasmania was completed recently. The sub-sea component of the pipeline is 330 km in length, while the onshore sections, including pipelines to Hobart and Port Latta, will total over 400 km.
- A gas pipeline from Port Campbell in Victoria to Adelaide is under construction at a cost of A$500 million. It will enable the transport of gas from the Thylacine and Geographe gas fields in the Otway basin to markets in Victoria and South Australia. The pipeline is to be commissioned and deliveries of gas are to commence by 31 December 2003.
- In February 2002, a Memorandum of Understanding (MOU) was signed between the PNG Government and the PNG Gas Project Joint Venture Partners, (represented by ExxonMobil Corporation) for a proposed US$ 3 billion project involving the construction of a 2,900 km gas pipeline from PNG down the eastern coastline through Townsville, Rockhampton, Gladstone and to Brisbane. However, a more westerly route to Mt Isa and Moomba is also possible.

A proposal is for a A$500 million power infrastructure package in North and Central Queensland, together with development of a new coal seam methane production field near Moranbah in the Bowen Basin. It involves the construction of a 391 km long, 250mm diameter pipeline from the field to Townsville and nearby Yabulu, and conversion of the existing open cycle oil-fired peaking plant at Yabulu to a 220 MW combined cycle, base-load gas-fired power station.

An extension of the Goldfield's pipeline from Kalgoorlie to Esperance (Western Australia) to supply natural gas is being proposed.

The expected completion by December 2002 of a short-distance pipeline connecting the Longford gas processing plant to gas pipelines supplying NSW, Victoria and Tasmania will establish the first commercial gas trading hub in the Australian market.

COAL

The Australian coal industry is going through a period of major expansion. Capital expenditure of A$2.5 billion has already been committed to projects that will expand production by around 45 Mt per annum over the next few years. Coal port terminals are expanding along with production. Competition has been promoted through the privatisation of railways in New South Wales and the Dalrymple coal port terminal in Queensland. Coal industry productivity has increased by over 15 percent per year since the introduction of work place relations reforms begun in 1997. These reforms together with the consolidation of mine ownership, new capital and technology will continue to support further improvements in productivity.

World thermal coal trade is expected to continue to grow strongly, despite slower world economic growth. The price of high quality coking coal has been increasing, reflecting supply shortages. The market is expected to remain tight even taking into account the impact of slower world economic growth on steel demand and production.

OIL AND GAS

A record number of oil and gas discoveries were made in Australia in 2001. These have greatly added to the reserves at end of 2000 stated above. This has helped address the perception held by a number of foreign companies that the chances of making further commercial discoveries of oil in Australia are low. The oil discoveries, in particular, have partly assuaged concerns over Australia's increasing oil import dependency that has risen to around 20 percent and predicted by some analyses to rise to around 40 percent by 2010[1]. A further 41 offshore petroleum exploration areas were released by the Government in April 2002. Bids closed for 7 of the areas on 24 October 2002 and will close for the remaining 34 areas on 10 April 2003.

Abundant gas resources and a long record as a reliable liquefied natural gas (LNG) supplier make Australia ideally suited to play an increasingly important role in the Asian energy scene. Recent important policy initiatives by the government, such as the LNG Action Agenda, provide a stable operating environment conducive to attract investment for export expansion.

Utilising large quantities of natural gas located off northern Western Australia, the North West Shelf (NWS) joint venture has developed a world class LNG facility on the Burrup Peninsula near Karratha. The NWS produces over 7.5 million tonnes per annum (mtpa) of LNG for export, valued at A$2.6 billion per annum, from three gas liquefaction trains, along with LPG and crude oil.

Plans to further expand the NWS project by adding a 4.2 mtpa fourth production train and second trunk line to meet expected growing demand in Asia were recently realised when China's State Development Planning Commission agreed to purchase 3.3 mtpa of LNG for the Shenzhen terminal. Also, the China National Offshore Oil Corporation is negotiating an equity stake in the NWS project. The A$2.4 billion expansion project is expected to be completed in mid-2004 and will be the largest facility of its kind in the world.

There are a number of hydrocarbon fields containing mainly natural gas in the Timor Gap between Australia and the newly independent economy of East Timor. The most significant of these are the Bayu Udan field, which is estimated to contain 400 million barrels of condensate and 68 BCM of natural gas, and the larger Greater Sunrise field, which is estimated to contain 263 BCM of natural gas. The two economies have agreed to split the royalties from the Bayu Udan field 90 percent to East Timor and 10 percent to Australia. The field operator, Phillips Petroleum, has contracted to supply 3 mtpa of LNG to two Tokyo utilities from 2006. The owners of the Greater Sunrise field are still considering development options.

Feasibility studies are in progress to evaluate the potential for LNG plants at green field gas areas in and around the North West Shelf, Northern Australia/Timor Sea, the Gorgon fields and Browse Basin.

[1] For example, APERC (2002), APEC Energy Supply and Demand Outlook to 2020.

There is also strong interest in the development of a gas to liquids (GTL) industry in Australia to take advantage of the abundant gas resources and provide cleaner transport fuels and greater self-sufficiency in liquid fuels. Proposals for a number of GTL projects in Australia are currently under consideration.

URANIUM

Australia is the world's second largest uranium producer after Canada. There are currently three operating uranium mines in Australia:

- Ranger Mine in the Northern Territory exported 4,255 tonnes of U_3O_8 in 2001.
- Olympic Dam in South Australia exported 4,525 tonnes of U_3O_8 in 2001. Plans have been developed to more than double the size of the project, raising U_3O_8 output to more than 8,000 tonnes per year.
- Beverley Mine in South Australia commenced operation in late 2000 and exported 460 tonnes of U_3O_8 in 2001. Nominal production capacity is 1,000 tonnes per year.

In late November 2001, environmental clearances were granted to develop the Honeymoon ISL project in South Australia to produce up to 1,000 tonnes per annum of U_3O_8, starting by the end of 2003. The Jabiluka mine in the Northern Territory continues to remain in a stand-by and environmental care and planning phase.

Australia has the largest resources of recoverable uranium of any economy in the world with about 29 percent of world reserves. Australian uranium exports in 2001 increased 5 per cent to 9,239 tonnes of U_3O_8, providing about 25 percent of world uranium supply from mines. Uranium comprises about of 42 percent of the country's energy exports.

Australia exported U_3O_8 to the following APEC countries in 2001:

- United States: currently Australia's largest market - 3,140 tonnes (supplying about 20 percent of US electricity);
- Japan: 3071 tonnes (supplying about 34 percent of Japan's electricity);
- Korea: 875 tonnes (supplying about 39 percent of Korea's electricity); and
- Canada: 210 tonnes (supplying about 13 percent of Canada's electricity).

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BRUNEI DARUSSALAM

INTRODUCTION

Brunei Darussalam is situated on the northwest of the island of Borneo. It has a total area of 5,765 square km with a coastline of about 161 km along the South China Sea. It is bounded on the north by the South China Sea and all other sides by the Malaysian state of Sarawak which divides Brunei Darussalam into two parts. The eastern part is the Temburong District, and the western part consists of Brunei-Muara, Tutong and Belait Districts. In 2000, the population of Brunei Darussalam was about 0.34 million.

The real gross domestic product (GDP) in 2000 was recorded at US$5.3 billion (1995 US$ at PPP), an increase of 2.8 percent over 1999. GDP per capita grew moderately by 0.4 percent that year to US$15,686 (1995 US$ at PPP).

Brunei Darussalam's economy is heavily dependent on oil and gas. Under the Five Year National Development Plans (NDP) the government outlines measures to diversify the economy through the establishment of downstream, higher-value-added industries, development of other natural resources, and increases in self-sufficiency and quality of life for the people. As a result, the contribution of the oil sector to the GDP has declined while that of the non-oil sector is increasing. The contribution of the oil sector at the end of the Seventh NDP period (2000) was about 37 percent while that of the non-oil sectors was 63 percent.

Brunei Darussalam's crude oil and condensate production for 2001 averaged 195 thousand barrels per day. Average gas production for 2001 was about 32 million cubic metres per day, most of which was exported to Japan and South Korea as liquefied natural gas (LNG).

Table 3 Key data and economic profile (2000)

Key data		Energy reserves**	
Area (sq. km)	5,765*	Oil (Proven)	223 MCM
Population (million)	0.34	Gas (Proven)	391 BCM
GDP Billion US$ (1995 US$ at PPP)	5.30	Coal (Recoverable)	0
GDP per capita (1995 US$ at PPP)	15,686		

Source: Energy Data and Modelling Center, IEEJ.

*Brunei Darussalam Statistical Year Book, 1999.

**Proved reserves, end of 2000, BP Statistical Review.

ENERGY DEMAND AND SUPPLY

PRIMARY ENERGY SUPPLY

In 2000, Brunei's oil and gas production was 17,066 ktoe, up 5.2 percent from 1999 production of 16,229 ktoe. Of this amount, 90 percent was exported. Total primary energy supply in 2000 was 1,852 ktoe which represented a 0.8 percent increase compared to 1999. Natural gas represents 87 percent of the total energy supply while oil represents 13 percent.

The economy's performance is expected to maintain steady growth in the near future due to stable exports of high-quality crude oil and liquefied natural gas (LNG). Brunei Darussalam has seven offshore fields. The largest field is Champion which holds about 40 percent of total oil reserves. The other main field is Southwest Ampa, the oldest field, which holds more than half of the economy's gas reserves and production. Total proven reserves are 223 MCM of crude oil. Oil is exported mostly to Japan, Korea, Singapore, Chinese Taipei and Thailand. Brunei Darussalam has natural gas reserves of 391 BCM, and long-term prospects for production are thought to be excellent. Most of Brunei's LNG is exported to Japan, with a small amount going to Korea.

In 2000, the total installed capacity for power generation in Brunei Darussalam, including the Independent Power Utility (IPU), was 707 MW. Approximately 99.7 percent of the electricity is generated from natural gas. Production for 2000 was 2,842 GWh which was 4.1 percent higher than 1999 production of 2,730 GWh.

FINAL ENERGY CONSUMPTION

In 2000, total final energy consumption of 636 ktoe was down by 4.3 percent from 665 ktoe in 1999. The transportation sector consumed 51 percent of the total amount, followed by other sectors (residential, commercial and non-energy) at 35 percent and industrial sector at 14 percent. By source, petroleum products contribute the largest share with 64 percent of consumption, followed by electricity at 33 percent and gas at 3 percent.

Table 4 Energy supply & consumption for (2000)

Total Primary Energy Supply	(ktoe)	Total Final Energy Consumption	(ktoe)	Power Generation	(GWh)
Indigenous Production	17,066	Industry Sector	91	Total	2,842
Net Imports & Other	-15,214	Transport Sector	324	Thermal	2,842
TPES	1,852	Other Sectors	220	Hydro	0
Coal	0	TFEC	636	Nuclear	0
Oil	240	Coal	0	Others	0
Gas	1,612	Oil	401		
Others	0	Gas	22		
		Electricity & Others	213		

Source: Energy Data and Modelling Center, IEEJ (see http://www.ieej.or.jp/apec/database/selecttable.html)

POLICY OVERVIEW

So far, Brunei Darussalam has implemented seven National Development Plans (NDPs). The long-term objectives outlined in these NDPs, particularly the current Eighth NDP, put specific emphasis on programmes to strengthen and expand the oil and gas industry, economic diversification through non-oil industries, maximum economic utilisation of national resources, improvements in the quality of life of the people, and promoting a clean and healthy environment. In pursuing these objectives, development plans will continue to focus on strategies and programmes that will expedite the process of industrialisation with a view to achieving more balanced socio-economic development. To encourage the private sector to play an active and important role in the development of the economy, the government is working to improve the investment climate.

OIL AND GAS

Prior to 1963, all mining activities including petroleum were regulated by the Mining Act. In 1963, the Government introduced the Petroleum Mining Act to cover all petroleum mining activities. The latter came with its own model concessionary agreements. Currently, exploration and production are carried out under such concessionary agreements. Under the Petroleum Mining Agreement between His Majesty's Government and the concessionaires, His Majesty's Government reserves the right to participate in the petroleum field upon declaration of commerciality.

In 1992, the Petroleum Mining Act was amended with all its schedules (including the Second and the Third Schedules) repealed. The move is partly due to the government's desire to introduce other forms of agreements (non-concessionary) for future petroleum mining activities. The amended act provides for procedures where the government may invite persons to bid for a petroleum mining agreement in respect of any onshore state land or offshore state land for the purposes of exploring for or mining petroleum. Any person so bidding shall conform to such terms and conditions as are imposed by the Government in the invitation to bid.

Amendments to the Petroleum Mining Act, made in January 2002, recognise the formation of Brunei National Petroleum Company Sdn Bhd (Petroleum Brunei). The company has the right to perform both commercial and regulatory functions. Among the regulatory functions is to act as a state party in the negotiation, conclusion and implementation of Petroleum Mining Agreements. New petroleum areas such as the deepwater Blocks J and K are to be awarded under Production Sharing Contract (PSC) with Petroleum Brunei's participation.

To prolong Brunei's oil reserves, the Brunei Oil Conservation Policy was introduced in 1980. It came into effect in 1981 and resulted in oil production around 150,000 barrels per day. Since November 1990, the government has given flexibility to the Conservation Policy which further increased production availability.

In 2000, the Brunei Natural Gas Policy (Production and Utilisation) was introduced. It seeks to sustain gas production levels in order to adequately satisfy current obligations. It also seeks to open new areas and to encourage more exploration activities by new and existing operators. It provides that priority shall always be given to domestic utilisation of gas, especially for power generation.

MACROECONOMIC PERFORMANCE

In 2002, oil and gas prices, together with the implementation of several government projects outlined in the Eighth NDP (2001-2005), remained the key factors in determining Brunei Darussalam's economic performance. Growth of the oil sector in 2001 was quite modest at 0.8 percent due to lower oil prices. Both government and private sectors are expected to grow at a rate of 2 to 3 percent per annum. Growth is anticipated especially in the non-oil sector which includes public utilities, transport and communications firms, and service industries.

In the medium-term, the following factors will influence economic performance:

- The BN$1 billion allocated for the implementation of the Eight NDP in 2002 which was announced by His Majesty the Sultan and Yang Dipertuan of Brunei Darussalam during the Seventh ASEAN Summit on 6 November 2001;
- Improvement of the business and climate to encourage foreign direct investment;
- Establishment of Brunei Darussalam as an international financial centre;
- Reduction in vehicle import tax since November 2001; and
- Production levels and the price of the oil and gas exports.

NOTABLE ENERGY DEVELOPMENTS

DEVELOPMENT OF DOWNSTREAM OIL AND GAS INDUSTRY

In an effort to diversify Brunei's oil and gas based economy, the government commissioned an international consultant to conduct the Brunei Darussalam Master Plan Study on Downstream Oil and Gas Industry. The study was completed in May 2001. The Master Plan Study identified:

- Gas based industry such as ammonia, urea and methanol;
- Derivatives of olefins and aromatics from naphtha cracker with the possibility of integration with a refinery; and
- Energy intensive industry such as aluminium smelters.

In June 2002, Petroleum Brunei called for expressions of interest for investment in the petrochemical projects to be located at the Sg Liang Industrial site in Kuala Belait. Investors will be shortlisted to conduct feasibility studies on their proposals. Selection for project implementation will be based on the results of the feasibility studies. The target for completion of the feasibility studies is the first half of 2003.

LNG SIXTH TRAIN EXPANSION OPPORTUNITY

Brunei LNG has embarked upon a program to expand its capacity from 7.2 million tonnes per year at present to 11.2 million tonnes per year by 2008. Brunei LNG will also refurbish existing capacity to extend its operating life by 20 years to 2033, aiming for continued LNG sales beyond 2013. Brunei LNG will invest around B$2.4 billion in these efforts over the next 13 years. The feasibility study will begin early 2003, and a final investment decision is expected in 2005.

OPENING OF NEW PETROLEUM AREAS

In new petroleum areas, two consortia bid for Block J (5,020 sq km), while only one bid was received for Block K (4,944 sq km) both situated offshore in the deep water Exclusive Economic Zone (EEZ). There was no bid for the onshore Block L (2,254 sq km), which is under review to develop strategies for re-offer, possibly with supplementary seismic data and revised fiscal terms.

On 29 January 2002, the government awarded Block J to a joint venture of TotalFinaElf, BHP Billiton, and Amerada Hess Corporation. TotalFinaElf (the designated operator) holds a 60 percent interest, while BHP Billiton holds a 25 percent interest and Amerada Hess holds the remaining 15 percent equity. The government has also awarded exploration rights to Block K to a joint venture which is led by Shell International (the designated operator) with a 50 percent interest and also includes Conoco and Mitsubishi with a 25 percent interest each. The awards were made subject to final negotiation and execution of a PSC with the government, which was expected shortly.

POWER SECTOR

In 2001, DES recorded a peak demand of 249.2 MW while BPC had a peak load of 159 MW. Total peak demand increased by about 4 percent over the previous year. To date, about 99.66 percent of the population has been provided with electricity from the power grid. The thousand or so people who are not connected to the grid live in villages that are not easily accessible, and they normally use small portable generators for their electricity needs. Projected yearly electricity demand growth is 7 percent for 2002 through 2005, 5 percent for 2006 through 2010, and 3 percent for 2011 through 2020.

The Department of Electrical Services has been formulating plans to meet increasing energy demand in line with economic development. In accordance with its mission to provide electricity supply in an efficient, reliable, safe and economical manner to upgrade the standard of living and promote economic development, the Department has embarked on several major power projects. In the Eighth National Development Plan period (2001-2005), the electricity sector has been allocated B$529.7 million or 7.3 percent of total development funds. Projects include:

- Replacement of retiring units at Gadong I Power Plant. This project adds 99 MW of installed capacity and a new twin overhead line circuit linking with the new power plant in Tutong District. It was to be completed by the end of 2002.
- Construction of a new 165 MW power plant in the Tutong District. Fuel pipeline and metering station have been completed., and earthwork is being carried out. To be re-tendered calling specifically for a combined-cycle plant.

- Extension of Lumut Co-generation Plant. This involves building six generator sets with installed capacity of 66 MW. Preliminary design work is complete.
- Installation of two 3 MW diesel generating sets in the Temburong District. This project was completed in 2001.

REDUCING THE OIL AND GAS INDUSTRY'S CONTRIBUTION TO GLOBAL WARMING

The oil and gas industry is one of the major contributors to global warming through the emission of methane and carbon dioxide (CO_2). The main sources of methane emissions are process venting, instrument gas and fugitives. Major sources of CO_2 emissions include process flaring, atmospheric gas flaring where recovery is uneconomic, fuel gas combustion (gas turbines and other prime mover exhausts), and transport.

As part of their environmental initiatives, major oil and gas producers in Brunei have targets to eliminate disposal of gas by continuous venting and flaring by 2003 and 2008 respectively. Projects undertaken to reduce venting include:

- Simplifying and rationalising old facilities, centralising processes at main complex facilities, and improving operations to reduce venting from compressor trips, fugitive losses, atmospheric gas disposal and from use of instrument gas;
- Converting existing vent stacks to flare stacks; and
- Simplifying and rationalising facilities to recover and recompress vented flash gas from surge vessels and to reduce instrument gas consumption.

Realising that fuel gas combustion contributes to a large percentage of CO_2 emissions, companies intend to focus more on improving the energy efficiency of gas turbines. Furthermore, new facilities will not be designed to continuously vent and flare gas for disposal, and instrument gas in new projects will not be allowed unless it is recovered. However, venting and flaring cannot be totally phased out. Venting and flaring will be limited only to atmospheric gas disposal, instrument gas in old facilities, fugitives (minimised), safeguarding measures (purge and pilot gas, and emergency relief) and process deviations (like compressor trips, or oil production during plant shutdown and maintenance), and it will take place under strict controls.

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CANADA

INTRODUCTION

Canada covers the northern part of North America and is second only to Russia in geographic size. Its small population of around 30 million, of which two-fifths is concentrated in the province of Ontario, is spread over 10 million square kilometres of territory. Canada is known for its wealth of energy and other natural resources. In 2000, its GDP amounted to roughly US$829 billion (in 1995 US$ at PPP), or US$26,945 per capita, representing a high standard of living.

Canada's economic picture has generally been very positive in recent years. Real GDP grew an average of 3.7 percent per annum in the late 1990s, with growth of 4.6 percent in 1999 and 4.5 percent in 2000. But the economy slowed substantially in 2001 and 2002, along with that in the neighbouring United States. Real GDP grew just 1.5 percent in 2001 and at just a 1.1 percent annual rate in the first half of 2002. Inflation remained low, at 2.7 percent in 2000 and 2.6 percent in 2001. Unemployment, which had fallen to 6.8 percent by the end of 2000, rose slightly during 2001, returned to 6.8 percent at the end of 2001 and rose as high as 7.7 percent during 2002.

Canada is the fifth largest energy producer in the world (behind the United States, Russia, China and Saudi Arabia) and a major energy exporter. It has abundant reserves of oil, natural gas, coal and uranium in its western provinces and enormous hydropower resources in Quebec, Newfoundland, Manitoba and British Columbia. It also has significant offshore oil and gas deposits near Nova Scotia and Newfoundland. At the end of 2000, energy reserves included 700 MCM of conventional crude oil, 27,810 MCM of oil in oil sands, 1,622 BCM of natural gas, 6,578 Mt of coal, and 437 kt of uranium. Installed electric generating capacity amounted to some 111 GW. Energy production is very important to the Canadian economy, accounting for 6 percent of GDP, 12 percent of merchandise exports and 290,000 jobs in upstream and downstream operations in 1999.

Due to Canada's cold climate, high standard of living and its many energy intensive and bulk goods industries, Canadians are also large consumers of energy. Canada's final energy consumption per capita in 2000 was 6.2 toe or about four times the APEC average.

Table 5 Key data and economic profile (2000)

Key data		Energy reserves**	
Area (sq. km)	9,984,670*	Oil	700 MCM***
Population (million)	30.75	Oil sands	27,810 MCM***
GDP Billion US$ (1995 US$ at PPP)	828.57	Gas	1,622 BCM***
GDP per capita (1995 US$ at PPP)	26,945	Coal (recoverable)	6,578 Mt

Source: Energy Data and Modelling Center, IEEJ.

*Statistics Canada.

**National Energy Board.

***Established reserves are the sum of proven reserves plus half of probable reserves.

ENERGY DEMAND AND SUPPLY

PRIMARY ENERGY SUPPLY

In 2000, Canada's energy production amounted to 380,515 ktoe, of which natural gas constituted 39 percent, crude oil 36 percent, coal 9 percent, hydropower 8 percent, nuclear power 5 percent and other sources 3 percent. Gross energy exports, primarily from western provinces, amounted to 199,769 ktoe or 52 percent of the energy produced. But there were also substantial energy imports, totalling 75,626 ktoe, mostly by eastern provinces, so net exports were just 33 percent of production.

Taking account of exports, imports and stock changes, Canada's domestic primary energy supply in 2000 totalled 263,536 ktoe or 69 percent of production. Of the primary energy supply, 37 percent was provided by crude oil and petroleum products, 29 percent by natural gas, 13 percent by coal, 12 percent by hydropower, 7 percent by nuclear power and 3 percent by other fuels.

Through 2000 and early 2001, oil and gas prices rose steadily, leading exploration, production and export revenue to increase. A record 17,983 oil and gas wells were drilled in 2001, exceeding the previous high of 16,507 wells drilled in 2000. Gas well completions increased by 16 percent in 2001, accounting for 69 percent of all wells completed. Oil well completions declined by 14 percent in 2001 as declining oil prices after the first quarter of the year caused drilling to drop off. Gas and oil production each increased by 2 percent in 2001. Gas exports grew a modest 3 percent in 2001, while oil exports were flat and electricity exports declined. But due to high market prices for energy, total gross export earnings for natural gas, petroleum, electricity and coal were a record CAN$58.0 billion in 2001, up from CAN$54.5 billion in 2000 and nearly double the level of CAN$30.4 billion in 1999.

Canadian crude oil production in 2000 amounted to a substantial 136,406 ktoe. Eastern Canada imports large amounts of oil, totalling 55,632 ktoe in 2000, up 9 percent from 1999. Western Canada exports even larger amounts of oil to the United States, totalling 93,588 ktoe in 2000 or 69 percent of production. During the 1990s, to feed strong growth in the North American transportation sector, domestic oil supply grew 3.0 percent per annum while net exports grew 3.6 percent per annum.

The largest source of crude production is the Western Canadian Sedimentary Basin (WCSB). Recent declines in light crude production have been offset by additional production of heavy crude. Conventional crude oil and natural gas liquids make up the bulk of oil production, but 29 percent of production in 2001 came in the unconventional forms of bitumen, synthetic crude and pentanes plus. Synthetic crude from oil sands in Alberta, which had a supply cost of some CAN$22 per barrel in the 1990s, is expected to grow in importance as technology lowers costs to CAN$15-$18 per barrel. Strong prices from late 1999 through early 2001 buoyed conventional oil and bitumen production in mature regions like the WCSB and encouraged expansion in newly developed resource basins on the East Coast. Hibernia, off of Newfoundland, came on stream in 1997 and produced 145,000 bbl/d in 2000, an increase of 45 percent from 1999. Terra Nova began production in late 2001.

Canada's natural gas production in 2000 totalled 148,899 ktoe, of which less than half went to domestic use. Net gas exports to the United States amounted to 81,353 ktoe, equivalent to 55 percent of production. Net exports were two and one-half times as large in 2000 as they were in 1990, when they amounted to just 37 percent of production. The export share has increased because during the 1990s, while domestic supply grew an average of 2.9 percent yearly, exports grew much faster at 9.2 percent yearly. In 2000, domestic supply grew 3.1 percent and exports 9.3 percent over 1999.

Gas production and exports are expected to remain strong over the next few years due to robust gas demand in the United States, expansions in pipeline capacity, and continued gas discoveries. The Maritimes and Northeast pipeline (M&NE) from the Sable Island gas field to New England went into operation at the end of 1999. The Alliance pipeline from Alberta to Chicago and the Vector pipeline from Chicago to Southern Ontario were completed in 2000; some 30 percent of the gas exported on Alliance is re-imported on Vector. Gas production began in the Ft Liard area of the Northwest Territories in 2000, flowing into the British Columbia grid. Two short pipeline expansions were approved in 2001, from British Columbia to Alberta and from Alberta to Saskatchewan.

In 2000, Canada produced 34,245 ktoe of coal, imported 17,354 ktoe, exported 19,116 ktoe and used 33,373 ktoe; so production and primary domestic supply of coal were approximately equal. This represents a major shift in the economy's coal balances over the three-year period from 1997. Largely because of increased use of coal-fired capacity in Ontario when eight nuclear power plants were taken out of service for refurbishment, imports of coal nearly doubled over the period. Meanwhile, heavy competition in international coal markets, where Canada's biggest customers are Japan and Korea, caused exports of coal to sag by about a quarter. So net coal exports fell from a substantial 16,047 ktoe in 1997 to just 1,762 ktoe in 2000. However, the situation may be expected to reverse, at least partially, due to the return to service of several nuclear power plants in 2002.

Canada generated about 605 TWh of electricity in 2000. Hydropower predominated with a 59 percent share, followed by thermal plants with 29 percent and nuclear power at 12 percent. Natural gas is increasingly favoured over coal for incremental thermal generation, owing to its reputation as a clean fuel and the availability of cost-effective combined-cycle generators for using it. There is substantial two-way electricity trade with the western United States, mostly among hydropower facilities. Net electricity exports to the US in 2000 amounted to roughly 6 percent of production.

Canada chose to develop nuclear technology due to its large domestic uranium reserves. It is the world's leader in uranium production, accounting for almost one third of world output. But the nuclear share of total generation, which peaked near 20 percent in 1994, has declined due to reactor aging and the temporary shut-down of eight nuclear power plants in Ontario in 1997-98. Coal- and gas-fired generation filled in for these laid-up plants. The nuclear share should rebound in 2002 since four Pickering A reactors returned to service in November 2001 (see notable developments below).

Table 6 Energy Consumption & Supply (2000)

Total Primary Energy Supply	(ktoe)	Total Final Energy Consumption	(ktoe)	Power Generation	(GWh)
Indigenous Production	380,515	Industry Sector	74,139	Total	605,204
Net Imports & Other	-116,979	Transport Sector	53,801	Thermal	173,792
TPES	263,536	Other Sectors	63,636	Hydro	358,413
Coal	33,373	TFEC	191,576	Nuclear	72,799
Oil	97,080	Coal	4,191	Others	200
Gas	75,190	Oil	77,356		
Others	57,894	Gas	55,533		
		Electricity & Others	54,497		

Source: Energy Data and Modelling Center, IEEJ (see http://www.ieej.or.jp/apec/database/selecttable.html)

FINAL ENERGY CONSUMPTION

In 2000, total end use energy consumption in Canada was 191,576 ktoe. Industry accounted for 39 percent of energy use, residential and commercial buildings for 31 percent, transport for 28 percent, and agriculture for 2 percent. By fuel source, petroleum products accounted for 40 percent of consumption, natural gas for 29 percent, electricity for 22 percent, coal for 2 percent and other fuels for the remaining 6 percent.

In the residential and commercial sectors, space and water heating account for approximately 70 percent of energy use while lighting, air conditioning and electronic equipment account for the remaining 30 percent. Growth in consumption has been slow, averaging just 0.9 percent per annum in the 1990s. Improvements in the energy efficiency of buildings, HVAC (heating, ventilation and air conditioning) systems and electronic equipment have helped to offset demand growth from increases in population and GDP. Other trends that suggest higher energy consumption in this sector include the increased market penetration of household appliances and office equipment as well as a strong consumer preference for larger homes and more powerful electronic equipment.

In the industrial sector, in 1999, three industries (pulp & paper, petroleum refining and iron & steel) accounted for approximately 6 percent of GDP yet were responsible for more than 40 percent of energy consumption. Energy is used to power equipment, to generate process heat and as a raw material in the production process. Energy consumption in the industrial sector grew on average 1.3 percent during the 1990s. Strong economic growth offset by efficiency improvements in some industrial sub-sectors, were the key factors behind consumption growth.

Boosted by both the passenger and freight segments, the transportation sector experienced the strongest average growth of all end-use sectors, 2.3 percent, in the 1990s. Petroleum products, at 89 percent of consumption in 1999, are the dominant fuels in the transport sector. Roughly four-fifths of transport demand, in terms of distance travelled, is met by road transport. Interesting trends on the passenger side of the market include the growing popularity of light trucks (including sport utility vehicles and minivans), which on average consume more fuel per kilometre than cars. Minimal fuel efficiency improvements in new vehicles and significant increases in average kilometres travelled per vehicle have also contributed to energy consumption growth. In the area of freight transport, economic growth has increased demand for truck freight and rail services. A shift away from rail towards more energy-intensive truck transport also pushed up energy demand in the freight sector.

POLICY OVERVIEW

In Canada, jurisdiction over energy matters is shared between the provincial and federal governments. The constitution gives the provinces authority over the conservation and management of natural resources within their borders. But jurisdiction over international and interprovincial trade is a federal responsibility. The division of power outlined by the constitution requires the different levels of government to cooperate in important policy areas such as climate change, environmental protection and regulation of gas and electricity grids. Through the Department of Natural Resources (NRCan), the federal government works with the provincial governments to implement national development strategies and to honour international agreements.

Energy policy in Canada is market-based. Due to its huge and diverse resource base, physical energy security is not an issue in Canada; however, sustainable development of existing resources to ensure adequate supplies for the future is a key priority. Policies are therefore aimed at promoting economic growth while encouraging conservation of resources and minimising environmental impacts. The Department of Natural Resources intervenes in areas where the market does not adequately support its policy objectives. NRCan therefore implements policies and programmes which encourage scientific and technological research. It also provides public information in the areas of energy efficiency, renewable and alternative energy sources, and energy resources generally.

OIL AND GAS MARKETS

Wellhead oil and natural gas prices in Canada have been fully deregulated since the Western Accord of 1985 was agreed by the federal government and energy-producing provinces. The Accord opened up the gas market to greater competition by permitting more exports, allowing users to buy directly from producers and unbundling production and marketing from transportation services. Oil and gas pipeline networks, over which competing oil and gas supplies are transported, continue to be regulated as natural monopolies. Federal authorities have the main responsibility for regulating long-distance, high-pressure transport networks, as well as exports. Provincial authorities have the main responsibility for regulating local and regional distribution networks.

The National Energy Board (NEB), a federal regulatory body under the Minister of Natural Resources, regulates oil and gas pipelines that cross international and inter-provincial borders and approves exports of oil, gas and electricity. In 1987, the NEB adopted a "market-based procedure" for approving export licenses; the market will be trusted to satisfy legal requirements that natural gas be provided at fair market prices. To improve market functioning, the NEB holds public hearings on applications to build or expand pipelines and establishes inter-provincial transportation rates, conditions of access and terms of service. To limit costly hearings, the NEB encourages large groups of shippers to negotiate pipeline rates directly with pipeline companies, subject to Board approval.

ELECTRICITY MARKETS

Electricity markets in Canada are organised along provincial lines and regulated by provincial governments. In most provinces, the power industry is highly integrated, with the bulk of generation, transmission and distribution provided by a few publicly owned utilities. But since the mid-1990s, driven in part by restructuring efforts in the United States, several provincial governments have brought in measures to make electricity markets in Canada more competitive. Such measures typically include the unbundling of major utility functions into transmission, generation, distribution and marketing segments. To obtain access to lucrative US export markets, British Columbia, Manitoba, Alberta, Quebec and Ontario have complied with rules of the US Federal Energy Regulatory Commission (FERC) and have opened up their transmission systems to competition.

Alberta has probably been the most active province in power market reform. In 1996, it introduced a competitive wholesale market, including location-based rates and a power pool. In 2000, it compelled electricity producers to sell their electricity output at auction to wholesalers. Since the start of 2001, it has allowed large and small electricity customers alike to choose among competing retail suppliers. But reform has not been without challenges. Rapid economic growth in the late 1990s sharply increased demand while uncertainty over rules for deregulation discouraged investment in power plants and curtailed supply. Because of this supply shortfall, consumers have faced price hikes of 80 percent or more since retail competition was introduced. Businesses are threatening to relocate. The provincial government maintains that new supply being added will bring prices down; meanwhile, to mollify consumers, it is offering temporary price rebates.

ENERGY END USE MARKETS

To promote energy efficiency and conservation in end use markets, Canada has generally opted for voluntary measures supplemented by information programmes such as product labelling, market incentives for certain types of investments and energy efficiency standards for household appliances, office equipment and industrial motors. In 1998, NRCan established the Office of Energy Efficiency (OEE). The OEE manages 18 programmes aimed at improving energy efficiency in the residential, commercial, industrial and transport sectors. To track the impact of these programmes on energy consumption, the OEE is developing a set of progress indicators.

ENERGY AND ENVIRONMENT

At the Kyoto conference in 1997, Canada agreed to reduce its greenhouse gas (GHG) emissions to 6 percent below 1990 levels by the period from 2008-2012, or to roughly 571 Mt in 2010. Yet by 1999, Canada's greenhouse gas emissions had grown to 705 Mt of CO_2 equivalent, 16 percent about 1990 levels. Under a "business as usual" forecast, emissions were projected to increase further to 770 Mt in 2010. To achieve the target will thus require policy actions to reduce emissions by about 200 Mt from the level projected and represents a Kyoto "gap" of approximately 26 percent.

In 1998, the federal, provincial and territorial governments established a National Climate Change Process to examine the impact, costs and benefits of Kyoto and the various implementation options open to Canada. To support this process, the federal government allocated CAN$150 million over three years to a Climate Change Action Fund (CCAF). Under the

CCAF, government and private sector experts worked in sixteen issue groups to develop and analyse options for reducing greenhouse gas emissions in different sectors like electricity, forestry and transportation.

To maintain momentum toward meeting Canada's climate change objectives, the February 2000 federal budget provided $625 million (CDA) for climate initiatives between 1999 and 2004. These include measures to develop and demonstrate new technologies like fuel cells, to support climate change and atmospheric research, to help municipalities implement environmental programmes, to expand purchases of green power in government operations, to reduce greenhouse gas emissions abroad, to renew the Climate Change Action Fund, and to extend proven energy efficiency and renewable energy programmes by three years through 2004.

In October 2000, Joint Ministers of Energy and the Environment, representing all provinces except for Ontario, unveiled the *National Implementation Strategy on Climate Change* and the *First National Climate Change Business Plan*. The Strategy provides a broad framework within which Canada's federal, provincial and territorial governments are jointly addressing climate change. The Business Plan outlines actions for implementing the strategy over a three-year period and is updated annually. To help implement the Business Plan, the government announced the *Action Plan 2000 on Climate Change*, which provided another $500 million (CDA) for climate change initiatives over a five-year period.

Initiatives outlined in *Action Plan 2000* include expanding the use of low or non-emitting energy sources by four times the current level, increasing the use of ethanol for gasoline blending, working with the United States to increase automobile fuel efficiency standards, investing in refuelling infrastructure for fuel cells, investigating the potential for geological storage of carbon dioxide, increasing interprovincial electricity trade, and improving the tracking and reporting of energy efficiency and carbon emissions by industry. *Action Plan 2000* is expected to reduce Canada's greenhouse gas emissions by 65 Mt per year by the first Kyoto compliance period of 2008-12. It will thus reduce the gap between projected and required emissions at that time by about one-third.

The federal government has made a commitment to reduce GHG emissions from its operations to 31 percent below 1990 levels by 2010. Since 1990, through retrofits, better fleet management and downsizing, energy use in federal buildings has been reduced by 19 percent.

NOTABLE ENERGY DEVELOPMENTS

ENVIRONMENT

PROGRESS TOWARD KYOTO TARGETS CONTINUES

At the September 2002 World Summit on Sustainable Development in Johannesburg, South Africa, Prime Minister Chrétien announced Canada's intention to ratify the Kyoto Protocol after full debate in the House of Commons by the end of 2002; ratification took place on 15 December. In support of ratification, the Government of Canada released its Climate Change Plan for Canada on 21 November as a starting point in the Kyoto implementation process. The plan sets out a detailed three-step-approach for achieving Canada's climate change objective of reducing annual GHG emissions by 240 Mt by 2012. First, investments to date should reduce emissions by 80 Mt or one third of the total required. Second, the plan articulates a strategy for a further 100 Mt reduction. Finally, the plan outlines a number of current and potential actions that should enable Canada to achieve the remaining 60 Mt of annual GHG reductions.

To achieve these emissions reductions, the Climate Change Plan proposes five key instruments:

- A Partnership Fund that will cost-share emissions reductions initiatives;
- Strategic investments in infrastructure projects including urban transit systems and a carbon dioxide pipeline;
- Increased investments in innovation technologies for climate change;

- Targeted measures, including information, incentives, regulations and tax measures; and
- Providing certainty for large industrial emitters in achieving emission reductions through a process for negotiating emissions-reduction covenants and provisions for emissions trading with access to domestic offsets and international permits.

The plan is consistent with principles that have been articulated since the start of consultations on how to address climate change. Specifically, the plan recognises the importance of:

- Collaboration, partnerships and respect for jurisdiction;
- No region bearing an unreasonable burden;
- Taking a transparent, step-by-step approach;
- Minimizing mitigation costs while maximizing benefits;
- Targeting information, incentives, regulations and tax measures;
- Recognising clean energy exports and early action by industry;
- Promoting innovation; and
- Limiting uncertainties and risks.

The federal government has committed to continue working with provincial and territorial governments, business and industry to refine the plan and develop implementation strategies.

EAST COAST LEADERS SIGN BILATERAL PACT TO REDUCE EMISSIONS

In August 2001, premiers from five eastern Canadian provinces (Newfoundland, New Brunswick, Nova Scotia, Prince Edward Island and Quebec) and New England governors from the US signed a bilateral agreement to reduce greenhouse gases in the region at least 10 percent below 1990 levels by 2020. The resolution calls on state and provincial governments to document the emissions levels in their regions, develop plans for reducing greenhouse gases, use more environmentally friendly fuels sources and reduce their energy consumption.

NUCLEAR POWER PLANTS REOPENING

In November 2001, the Canadian Nuclear Safety Commission announced its decision to allow the four Pickering A nuclear power plants, owned by Ontario Power Generation, to resume service. The plants, which have 2 GW of capacity in all, were commissioned in 1971 but had been taken out of service near the end of 1997 to be overhauled. The company estimates that the cost of their refurbishment was 35 to 40 percent less that than building fossil-fuelled plants of equal capacity. The plants now have enhanced systems for emergency shutdown, including a shutdown control room, new sensors for detecting abnormalities in the rate of heat transport and energy production, and a manual shutdown facility in case automatic systems should fail. In addition, the plants have better monitoring of radioactive emissions and improved protection against fires and earthquakes.

Ontario Power Generation has leased the Bruce power station, including four reactors that are operating and four that are currently out of service, to Bruce Power, a consortium led by British Energy PLC. The lease, which was finalised in May 2001, runs until 2018 with an option to extend by 25 years. Effective with the financial close of the lease, the Canadian Nuclear Regulatory Commission granted Bruce Power operating licenses for all eight units. The consortium plans to overhaul two of the reactors that are currently out of service and restart them by 2003.

ELECTRICITY MARKET REFORM

Ontario expects to open its wholesale and retail electricity markets to competition in 2006. The market opening was originally intended to occur on May 1, 2002, but it has been delayed in response to fluctuating electricity prices in the province. The provincial government has proposed several actions that will increase available power supply over the next four years, allowing for market reform to proceed within a more stable electricity supply framework.

The groundwork for reform was laid by the Energy Competition Act of 1998 that ended the long-standing monopoly on electricity supply that had been held by the provincially-owned utility, Ontario Hydro. The Act unbundled the vertically integrated monopoly into distinct entities for generation, transmission, market operation, finance and safety. The generation company, Ontario Power Generation, must compete with other power producers and has until 2010 to reduce its share of the provincial electricity market to 35 percent from the 85 percent share it held when the Act was signed (the rest being imported from neighbouring Quebec). To allow for progress toward this goal, investors have been invited to apply for licences to buy and sell electricity.

The transmission entity, Hydro One, is in principle to be privatised as a regulated monopoly. But the Ontario Superior Court ruled that the provincial government did not have legislative authority to sell the grid assets; the provincial government is appealing the ruling. Local distribution companies, most of which are municipal electric utilities, were required by the Act to separate their wires businesses, which will remain regulated as natural monopolies, from their retail supply businesses, which will be competitive. The provincial government is confident that the recent re-opening of the Pickering A nuclear units, which will boost available supply by about 10 percent, should help ensure a supply surplus and lower prices, improving the chances of successful market reform.

In British Columbia, an energy policy task force reporting to the Minister of Energy and Mines made recommendations in March 2002 for a move to fully competitive electricity markets. British Columbia Hydro and Power Authority (BC Hydro), which is currently a vertically integrated utility with monopoly franchise, would be separated into operating entities for power generation, transmission and distribution. Fair access would be provided to the transmission system for all competing generators. A transition mechanism would gradually move consumer prices to market levels, which are higher than current prices, in order to attract needed investment in new supply. A final energy plan, incorporating many of the recommendations of the energy policy task force, was released on 25 November. The plan upholds the recommendation to split up BC Hydro.

In New Brunswick, a restructuring plan for the electricity sector was outlined in a white paper in January 2001. Under this plan, wholesale competition would be introduced by April 2003, with generation allowed by non-utility entities. Recommendations on the structure and rules for a competitive electricity market were made to the provincial government in April 2002. Nova Scotia also announced plans for a competitive electricity market in December 2001. Under these plans, utilities and independent generators would be able to access the transmission system on equal terms.

Several Canadian utilities took steps during 2001 to coordinate their operations with regional transmission organisations (RTOs) being set up under market reform proposals by the U.S. Federal Energy Regulatory Commission (FERC). In September, Manitoba signed a coordination agreement with the Midwest Independent System operator. In December, RTO West's submission to the FERC included a proposal for participation by BC Hydro. Alberta, through its energy department, transmission operator and power pool, is also considering participation in RTO West. Ontario has been assessing the merits of alternative options for joining RTOs in adjacent US markets as well.

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CHILE

INTRODUCTION

Chile, one of the two APEC economies in South America, covers nearly 757,000 square kilometres. The population lives mainly in urban areas, with nearly one-third of its 15 million inhabitants residing in Santiago, the capital. Chile is a major producer and exporter of copper.

Chile's GDP in 2000 was US$138.1 billion while GDP per capita was US$ 9,081 (both in 1995 US$ at PPP). The economy grew at an average annual rate of 5.4 percent during the decade from 1990 to 2000. Due to Chile's dependence on exports, the Asian financial crisis of 1997-98 reduced its growth considerably in 1999, and the global economic slowdown did so in 2001-02. In 2002, Chile signed free trade agreements with Korea and with its main trading partner, the European Union. It soon expects to sign similar agreements with Japan and the United States.

Chile is endowed with modest energy resources that do not meet all of its energy needs. As of 1999, its energy reserves consisted of 4.8 MCM of oil, 45 MCM of natural gas and 155 Mt of coal. In 2000, roughly two-fifths of its total primary energy supply was produced indigenously.

Table 7 Key data and economic profile (2000)

Key data		Energy reserves*	
Area (sq. km)	757 000	Oil (Proven)	4.8 MCM
Population (million)	15.21	Gas	45 BCM
GDP Billion US $ (1995 US$ at PPP)	138.13	Coal	155 Mt
GDP per capita (1995 US$ at PPP)	9,081		

Source: Energy Data and Modelling Center, IEEJ.

*1999 figures from National Energy Commission (CNE), Chile.

ENERGY DEMAND AND SUPPLY

PRIMARY ENERGY SUPPLY

From 1980 to 2000, Chile's total primary energy supply (TPES) grew by an average of 4.6 percent per year, reaching 27,178 ktoe in 2000. Of this total, 38 percent was provided by crude oil, 20 percent by natural gas, 11 percent by coal and 30 percent by other sources, mainly biomass and hydropower. In 2000, natural gas supply surged by 31 percent, while renewable energy supply jumped 52 percent. Meanwhile, coal supply dropped by 18 percent and oil supply declined by 2 percent. An important development in Chilean energy markets was the introduction of natural gas from Argentina in 1997. In just two years, natural gas became the second most important source of primary energy in Chile.

Chile's dependence on energy imports had been growing steadily until 1999. In 1980, approximately 64 percent of TPES was indigenous production and 36 percent net imports. By 1999, this relationship was reversed, and indigenous production accounted for only 29 percent of the total. In 2000, however, indigenous production rose to 39 percent of TPES, due mainly to an increase in hydropower and biomass energy supply, while coal imports declined.

During most of the past two decades, imports have increased for several reasons. Due to dwindling reserves, domestic crude oil production peaked in 1982 at 32 percent of domestic supply and has declined to just 3 percent of domestic supply in 2000. A non-competitive coal industry has led to a considerable increase in coal imports. Domestic coal accounted for only 8 percent of

Chilean consumption in 2000, down from nearly 70 percent in 1980. The gas market has been transformed by imports from Argentina in the more populous north and central regions since 1997. Previously, due to infrastructure constraints, gas was only available in the south.

Empresa Nacional del Petróleo (ENAP), a state-owned company, produces and refines oil in Chile. Due to dwindling domestic resources, the company is increasing exploration and production activity abroad (mainly in Latin America and North Africa), through its international subsidiary, SIPETROL. ENAP is working towards a goal to supply 30 percent of Chilean oil demand. Oil is imported mainly from Argentina, Ecuador, Nigeria, and Venezuela. Both retail and wholesale markets for refined petroleum products operate on a competitive-basis. There are three refineries in Chile: Petrox Talcahuano (100,640 bbl/d throughput capacity, scheduled to increase 25 percent by the first quarter of 2002), Refinería de Petróleo de Concón (94,350 bbl/d) and Gregorio Magallanes (9,859 bbl/d).

In 2000, 40,700 GWh of electricity were produced in Chile. Over the period 1980 to 2000, production increased by 6.4 percent per annum. Historically, hydropower accounted for the bulk of installed capacity and electricity generation. By 2000, however, thermal plants accounted for almost 60 percent of total capacity and slightly over 50 percent of generation. The introduction of natural gas from Argentina has encouraged the construction of natural gas-fired combined cycle plants and increased the importance of thermal generation. Thermal generation relies mainly on natural gas and coal plants, coming 42.9 percent from gas and 36.2 percent from coal, but there is also some generation with fuel oil, biomass, and other fuels (21.0 percent). The use of petroleum coke (petcoke) was recently approved in some plants under controlled environmental restrictions.

Table 8 Energy supply & consumption (2000)

Total Primary Energy Supply	(ktoe)	Total Final Energy Consumption	(ktoe)	Power Generation	(GWh)
Indigenous Production	10,729	Industry Sector	5,776	Total	40,700
Net Imports & Other	16,449	Transport Sector	6,634	Thermal	21,562
TPES	27,178	Other Sectors	7,224	Hydro	19,138
Coal	3,099	TFEC	19,634	Nuclear	0
Oil	10,393	Coal	791	Others	0
Gas	5,427	Oil	10,617		
Others	8,258	Gas	1,104		
		Electricity & Others	7,122		

Source: Energy Data and Modelling Center, IEEJ (see http://www.ieej.or.jp/apec/database/selecttable.html)

There are four separate power grids in Chile. Sistema Interconectado Central (SIC – Central Interconnected System) is the most important. It serves over 90 percent of the population and more than 40 percent of the land area; its installed capacity as of December 2001 was 6,579 MW, of which 61 percent was hydro. Sistema Interconectado del Norte Grande (SING – Great North Interconnected System) serves mainly mining consumers; its installed capacity as of December 2001 was 3,441 MW (including 643 MW in Argentina), almost entirely thermal. Sistema Aysén and Sistema Magallanes, the other two grids, represent only a small portion of installed capacity.

Several gas pipelines have been built between Argentina and Chile since 1997. The energy supply grid between the two economies also includes a power transmission line in the north and several oil pipelines. In all cases, energy flows in one direction, from Argentina to Chile. The two economies are discussing further cooperation in the power sector, including measures to facilitate the integration of their electricity networks. Energy sector collaboration in Chile and Argentina is part of a larger integration process in South America and in MERCOSUR (Mercado Comun del Sur or Common Market of the South) which is formed by Argentina, Brazil, Paraguay and Uruguay with Bolivia and Chile as associate members.

FINAL ENERGY CONSUMPTION

Chile's total final energy consumption (TFEC) grew at an average annual rate of 4.4 percent from 1980 to 2000, reaching 19,634 ktoe at the end of the period. The main energy-consuming sectors are transport (34 percent) and industry (29 percent) with residential, commercial and public sectors consuming 37 percent. By energy source, oil products account for 54 percent of final consumption, electricity and "other" sources 36 percent, gas 6 percent, and coal 4 percent.

Chile is the world's largest copper producer and is expected to account for nearly 40 percent of world production in the medium term. The copper industry is by far the most important industrial energy consumer in Chile. A major copper development project can make energy demand jump sharply. Changing production methods, particularly penetration of hydro-metallurgical processes, have led to an increase in electricity consumption by the copper industry.

Energy consumption in the industrial sector is highly concentrated, with three industries accounting for nearly half of it. The copper industry leads with 25 percent of industrial energy consumption and 9 percent of TFEC. It is followed by the pulp and paper industry, with 17 percent of industrial energy consumption, the iron and steel industry with 8 percent, and the cement and fishing industries, each with 3 percent. However, in the decade from 1990 to 2000, most of the 6.6 percent annual growth in industrial energy use was driven by non-energy-intensive industries, whose demand grew 9.1 percent yearly. When total industrial energy consumption is broken down by fuel, oil products account for 32 percent, electricity for 30 percent, biomass for 15 percent, coal and coke for 10 percent and natural gas for 10 percent. Gas has been substituting for oil products (especially heavy fuel oil) and coal in the industrial sector, especially since the introduction of Argentinean gas in northern and central Chile.

Transportation has recently been the fastest-growing end-use sector, its energy use increasing an average of 6.9 percent per annum for the decade from 1990 to 2000. In 2000, road transport was responsible for 76 percent of energy consumption in transport. Oil products accounted for 99.6 percent of sectoral energy consumption, electricity 0.3 percent and natural gas 0.1 percent.

In the residential, commercial and public sectors, growth in energy use has been slower, averaging 4.5 percent per annum from 1990 to 2000. Among these sectors, the residential sector accounted for 88 percent of energy consumption in 2000. Biomass (mostly firewood) is the most important fuel in this sector, accounting for 52 percent of consumption in 2000, while oil products accounted for 25 percent and electricity 17 percent. The share of natural gas (6 percent) is expected to continue increasing due to the availability of imported gas from Argentina.

POLICY OVERVIEW

Energy policy in Chile aims to promote dynamic development in the energy sector, overall economic growth and a better quality of life for its citizens. The government has stated that development of the energy sector should be consistent with the following principles:

- Improvement of energy supply conditions as well as the quality and security of energy products and services;
- Reduction in the prices of energy products and services, within reason, in order to reflect technological and managerial advances, improve the economy's international competitiveness, maintain incentives for investment, and offer consumption opportunities to the poorest segments of the population;
- Protection of energy consumers by minimising abnormal fluctuations in prices of key products, especially those caused by temporary distortions in markets;

- Focused and transparent support, through efficient and effective mechanisms, to sectors that do not have access to key energy resources, where providing such access has a high social priority or social return;
- Development of and compliance with regulations that protect the environment.

In other words, the main objective of Chile's energy policy is to achieve strong energy supply and economic growth, without comprising the welfare of energy consumers, key industries or the environment. The general guidelines for achieving this objective are as follows:

- Assure an adequate degree of regulatory stability to minimise risks to investment, while upgrading and improving the regulatory framework with prudence and timeliness;
- Strengthen local competition, increase participation in international markets, and increase energy diversification;
- Create conditions where the prices and quality of energy products and services approach those theoretically obtainable in perfectly competitive markets;
- Foster sustainable development and efficient use of energy;
- Contribute to social equity using economically transparent mechanisms;
- Monitor energy security;
- Take advantage of international opportunities and anticipate potential problems.

An example of policy supporting these objectives is energy sector privatisation. Chile was the first economy in the world to restructure its power sector, almost a decade before the United Kingdom. The market reform strategy that Chile developed twenty years ago has served as a model for other economies in South America. Currently, the basic law regulating the power sector is being modified to increase competition and improve consumer protection.

NOTABLE ENERGY DEVELOPMENTS

INTERNATIONAL ENERGY INTEGRATION

Chile is engaged with other South American economies in a process to diversify its energy matrix and strengthen bilateral relations to ensure adequate energy supply.

PERU

The Presidents of Chile and Peru have agreed to start bilateral conversations leading to the future subscription of an Energy Integration Protocol.

ARGENTINA

Energy integration with Argentina has progressed more than with any other economy. This has had a significant impact in Chile's energy matrix, especially in the case of natural gas imports. Chile is also interconnected with Argentina through a power line, and there are plans for more lines between the two economies. The web site of the Electricity Market Information Exchange Protocol between Chile and Argentina was scheduled to be implemented in November 2002.

ECUADOR

A Memorandum of Understanding for Cooperation on Energy Issues between Chile and Ecuador was signed in Quito on July 29, 2002. The aim is to strengthen bilateral relations and to join efforts to improve the performance of the energy sectors of each economy.

LNG TERMINAL FOR PACIFIC LNG GAS FROM BOLIVIA

Bolivia is considering Chile and Peru as possible transhipment points for natural gas from the Pacific LNG project. The US$ 6 billion pipeline will transport 850 million cubic feet per day of gas from the Margarita Field in southern Bolivia (which has proved reserves of 6 trillion cubic feet of gas and over 140 million barrels of condensate) to either Antofagasta in Chile or Ilo in Peru. There the gas will be converted into LNG and shipped to a receiving terminal in Ensenada, Baja California, Mexico. The gas will be sold to Mexican and US (California) markets.

MODIFICATIONS TO THE ELECTRICITY LAW

The Chilean government announced a draft bill to change the General Law of Electrical Services of 1982 on 13 September 2000. The objective of this initiative is to increase the flexibility of the existing legal framework, so that the electric power sector has the tools to adapt successfully to the changing national and international economic climate. A favourable investment climate, a more competitive market, and regulatory procedures that are stable and transparent should make the sector more efficient, improving the reliability and quality of power supply. Increasing electrification, particularly in rural and isolated areas, is also a priority.

The goal of proposed changes is to improve economic incentives and encourage efficiency in the competitive segments of the electricity market. Where market intervention by regulatory agencies is necessary, this intervention should increase sectoral efficiency, economic equality and the active participation of energy consumers in the market. In achieving these goals, environmental law and regulations will play an important role.

The government decided to separate the bill in two parts. The first one, Law I (Short Law) seeks to correct the most urgent distortions to security of supply and investment. Law II (Long Law) aims to eliminate distortions that have long-term effects. It would redesign the system of distribution tariffs, introduce power marketers, and require that load dispatch centres operate to truly open up the electricity market to all large consumers, generators and distributors. The six points included in Law I are:

- Re-design of the regulation for transmission systems;
- Tariffication in medium-sized systems;
- Regulation of ancillary services;
- Requirements for the transfer of concessions;
- Reduction of the price band used in the determination of node prices; and
- Basic procedure to calculate distribution tolls.

Law I was sent to the lower house of Congress on 6 May 2002 and is still under discussion. The Senate will further discuss this bill. The National Energy Commission (CNE) is also reviewing the Electricity Regulation (Reglamento Eléctrico), which states the operational details contained in the new laws.

HYDROCARBONS

Regulations are being revised to improve the quality of service in natural gas distribution and to enhance the operational security of the gas transportation network, control and dispatch centres. The regulatory changes will incorporate lessons from an emergency in February 2002 when gas supplies from Argentina were cut for several hours. They will also be influenced by a CNE study of the impact of current gas regulation on different energy market participants. In addition, CNE is preparing a technical regulation on infrastructure security of LNG facilities.

RURAL ELECTRIFICATION

To improve quality of life in rural areas of Chile, the government initiated the National Programme for Rural Electrification (PER) in 1994. The programme has played an important role in improving access. In 2000, the percentage of rural homes with access to electricity was 78.1 percent, up 21 percentage points from the 1993 level. In 2001, this figure reached 79.5 percent, raising the national total to 96.8 percent of the population. The goal is to increase coverage in rural areas to 90 percent by 2006. The rural electrification program considers both grid extension and renewable energies such as photovoltaic and wind power.

RENEWABLE ENERGY

Renewable energy is being considered in the discussion about energy security in Chile. It is seen as one more option to increase and diversify supply to the grid. The first wind farm in Chile was inaugurated in November 2001 in the southern town of Alto Baguales, Coyhaique. The US$2.4 million investment by SAESA, a private utility owned by PSEG, includes three turbines with a total capacity of 2MW. It will meet 16 percent of demand in the Aysén Electric System. Some geothermal sources have also been explored considering their possibilities to be developed as power generation projects.

ENVIRONMENT

Chile ratified the Kyoto Protocol on 9 July 2002. It is expected that the National Commission for the Environment (CONAMA) will have measures in place to use the Clean Development Mechanism (CDM) by early 2003. CNE will help implement these measures.

The first approved CDM project in Latin America, the Chacabuquito Hydro Project, started producing energy in July 2002. The 25MW run-of-the-river power plant is located some 100km northeast of Santiago, Chile's capital. The project obtained support from the Carbon Prototype Fund of the World Bank. It is expected to reduce emissions by approximately 6.9 Mt of CO_2 during its lifetime. An agreement to buy 11,000 tonnes of its emissions reduction has been reached between the Chilean company Hidroeléctrica Guardia Vieja S.A. and Mitsubishi of Japan.

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CHINA

INTRODUCTION

China is the world's most populous economy with 1.26 billion citizens. It has a geographical size of 9.6 million square kilometres. Currently China is the world's second largest energy consumer behind the United States and the third largest producer behind the United States and Russia. However, per capita energy consumption levels (at 0.4 toe) are far lower than in many developed economies and also below the world average.

China has sustained high rates of economic growth, just under 10 percent, for more than 20 years. However, in the late 1990s, growth slowed slightly to about 8 percent per year. Energy demand also grew rapidly through most of the 1990s but has dropped off since 1997. Per capita incomes are still quite low, US$ 3,817 (1995 US$ at PPP) in 2000.

China possesses large amounts of energy resources, particularly coal. It is the largest producer and second-largest consumer of coal in the world, as well as the seventh largest producer and third largest consumer of oil. After decades as a net oil exporter, China became a net oil importer in 1993. According to recent estimates, China has recoverable coal reserves of some 114.5 Gt, proven oil reserves of 3,816 MCM and proven natural gas reserves of 1,370 BCM. In addition, China is endowed with 676 GW of technical hydropower potential, more than any other economy in the world. For power generation and industrial development purposes, coal and oil resources have been utilised more extensively than reserves of gas and hydro potential.

Table 9 Key data and economic profile (2000)

Key data		**Energy reserves**	
Area (sq. km)	9,600,000	Oil (Proven)	3,816 MCM*
Population (million)	1,262.46	Gas (Proven)	1,370 BCM*
GDP, Billion US$ (1995 US$ at PPP)	4,818.47	Coal (Recoverable)	114.5 Gt*
GDP per capita (1995 US$ at PPP)	3,817	Hydropower (Potential)	676 GW**

Sources: Energy Data and Modelling Center, IEEJ.

*Proved reserves, end of 2000, *BP Statistical Review*.

**China Energy Annual Review 1997.

ENERGY DEMAND AND SUPPLY

PRIMARY ENERGY SUPPLY

Following two decades of continuous growth, total primary energy supply (TPES) in China peaked at 847,829 ktoe in 1996 and declined to 717,752 ktoe by 2000. The recent decline has been mainly due to slower growth and structural changes in the Chinese economy. Of this total, coal accounts for 64 percent, oil for 30 percent, and natural gas for 3 percent; hydropower, nuclear power and other sources account for the remaining 3 percent.

In the past, to ensure security of supply, development of China's abundant indigenous coal reserves was given much political and financial support. In the 1990s, to reduce pollution and emissions from energy use and to optimise the existing energy structure, Chinese authorities began to encourage fuel switching from coal to cleaner fuels and introduced energy efficiency initiatives. Since coal use peaked in 1996, it has declined 25 percent, and production of coal has declined in response. Overall Chinese energy production fell from 849,677 ktoe in 1996 to 675,970 ktoe in

2000. Reduced energy consumption has helped to reduce pollution and minimise harm to the environment.

In 2000, imports provided around a third of crude oil and petroleum product requirements. China's oil output in 2000 was about 160 million tons, nearly the same as in 1999. Most of China's oil reserves are onshore, with the largest production fields in the northeast at Daqing and Liaohe. These fields are maturing, and their output may begin to decline in the near future.

Gas production and consumption in China are currently quite small, just 3 percent of total primary energy supply. However, in the last few years, Chinese authorities have begun to promote gas use in power generation and industry, as well as in the residential sector. Gas is attractive since it is a cleaner fuel than coal and because China has abundant gas reserves. Its gas resources are located mostly in western China whereas demand is in large cities on the eastern seaboard. Therefore, the government is investing in pipeline infrastructure, including a "West to East" pipeline from Xinjiang (Uygur Autonomous Region) to Shanghai, to facilitate gas use.

Table 10 Energy supply & consumption (2000)

Total Primary Energy Supply	(ktoe)	Total Final Energy Consumption	(ktoe)	Power Generation	(GWh)
Indigenous Production	675,970	Industry Sector	301,774	Total	1,355,600
Net Imports & Other	41,782	Transport Sector	59,233	Thermal	1,116,449
TPES	717,752	Other Sectors	192,059	Hydro	222,414
Coal	457,536	TFEC	553,066	Nuclear	16,737
Oil	213,875	Coal	240,267	Others	0
Gas	22,791	Oil	181,515		
Others	23,550	Gas	23,497		
		Electricity & Others	107,786		

Source: Energy Data and Modelling Center, IEEJ (see http://www.ieej.or.jp/apec/database/selecttable.html)

The power industry in China has experienced very high growth in recent decades. Total installed capacity grew from 66 GW in 1980 to more than 300 GW by 2000. In 2000, electricity generation grew by 9 percent to 1,356 TWh. Thermal plants, mostly coal-fired, accounted for 82 percent of generation, while hydropower generation accounted for 16 percent and nuclear power for 1 percent. By the end of 2000, total installed hydropower capacity had reached 79.4 GW, only 11.7 percent of the total of technically exploitable resources. A number of huge hydro projects such as the Three Gorges project are under construction and will substantially increase power generation capacity.

FINAL ENERGY CONSUMPTION

Final energy consumption in China reached 553,066 ktoe in 2000. Industry was the largest user accounting for 55 percent of energy consumption. Transportation accounted for 11 percent of energy use and other sectors 35 percent. In terms of fuels, coal (43 percent) was the most important, followed by oil (33 percent), electricity, heat and other fuel (19 percent), and gas (4 percent). Over the last two decades, China has greatly reduced the energy intensity of its economy through energy conservation measures, from 2.2 toe per thousand 1995 US$ of GDP in 1980 to 0.7 toe per thousand 1995 US$ of GDP in 2000.

POLICY OVERVIEW

In the last 20 years, strong economic growth in China has been supported by economic policies promoting openness and reform. Energy supply has kept pace with strong demand due to increased investment, improved management practices and the adoption of new technologies. Moreover, policies promoting greater openness have permitted energy imports to become a more significant component of domestic supply.

The government's policy of stimulating domestic economic growth through energy sector investment is expected to continue. Total investment in fixed assets in the energy sector was RMB 238.4 billion in 1999. Investment in the coal industry was RMB 8.7 billion and RMB 64 billion was invested in oil and gas exploration and pipeline construction. Investment in the power industry totalled RMB 165.7 billion, of which RMB 61 billion went to power grid construction and improvement (RMB 21.3 billion in urban areas, RMB 39.7 billion in rural areas) and RMB 104.7 billion went to construction of generating plants, with a focus on large-scale hydropower projects and clean-coal pilot projects. Power industry investments have not only increased the amount of power to meet growing demand, but have made delivery of power more efficient and reliable.

China has substantial energy resources, but they are not well distributed with respect to energy demand. Natural gas reserves are located in the western provinces of Xinjiang, Sichuan, Qinghai, Shaanxi and Gansu. Coal reserves are concentrated in the western provinces of Shanxi, Shaanxi and Inner Mongolia. Hydropower resources are mainly located in the southwest. But energy demand is concentrated in the eastern provinces of Guangdong, Zhejiang, and Jiangsu, especially in Shanghai, Beijing, Tianjin and other cities near the ocean. To boost growth in China's west, the government considers that development of natural gas, water resources and coal reserves located in the southwestern and northwestern provinces should be accelerated.

China issued its Tenth Five-Year Plan for National Economical and Social Development in March 2001. The Plan defines objectives, guiding principles and major tasks for China's economic and social development from 2001 through 2005. It proposes that "energy development should take China's energy resources as a basis for development, optimise the development of energy structure, accelerate international energy supply and foreign collaboration, improve energy efficiency, promote new and renewable energy and intensify environmental protection."

ENERGY DEVELOPMENT TARGETS FOR TENTH FIVE-YEAR PLANNING PERIOD

As part of the Tenth Five-Year Plan, the State Development Planning Commission (SDPC) issued a "special energy development plan" to guide the energy sector from 2001 through 2005. China's energy strategy during this period is to guarantee energy security, optimise energy industry structure, improve energy efficiency, protect the environment, and accelerate development of energy infrastructure in the western region of China where energy resources are abundant. In accordance with this strategy, there are several major targets for energy development:

- By the year 2005, total primary energy output is expected to reach 1,320 Mtce. Coal production is expected to reach 1,170 Mt, oil production 165 Mt, natural gas production 50 BCM, and electricity generation 1,730 TWh. Hydropower is expected to provide 356 TWh and nuclear power 60 TWh. Total electric generating capacity is expected to reach 370 GW.
- Compared with 2000, the percentage of coal in total energy consumption is expected to drop 3.9 percent by 2005, and clean energy such as natural gas and hydropower is meanwhile expected to increase to 17.9 percent of the total.
- From 2001 to 2005, energy intensity, or ratio of energy use to GDP, is projected to decline by 15 to 17 percent, reducing energy requirements in 2005 by 300 to 340 Mtce.

ENERGY SECURITY

Domestic supplies of oil and natural gas can no longer keep pace with China's needs. To ensure an adequate supply of energy as the economy develops, the government is implementing measures to conserve and substitute for oil, as well as to accelerate the exploitation of oil and gas resources. To minimise the risk of supply disruptions, energy imports will be diversified and petroleum stockpiling will be established and gradually improved. To reduce reliance on imported energy, oil substitutes will be developed and the application of coal liquefaction technologies will be promoted.

STRUCTURAL OPTIMISATION

Optimising the structure of the energy sector will also be a priority in future energy development. During the Tenth Five-Year Plan period, as the balance between demand and supply improves, the focus of energy sector development should be shifted to sustainable development and environmental protection. Achieving this goal will require changes in the structure of the energy industry as well as the development and application of advanced technologies.

Energy self-reliance is a key policy goal in China, and development of the economy's abundant indigenous coal reserves has therefore received much political and financial support. Coal will continue to be China's main source of energy, but its share of energy supply is expected to decline. In recent years, the historical energy shortage has lessened, and serious air pollution problems have put pressure on the government to seek means of using coal more cleanly, as well as to develop clean alternatives to coal. A high-technology structure will be introduced to focus the use of coal in power generation and liquefaction, encourage use of pollution control technologies at coal-fired power plants, and promote cleaner fuels. A national clean coal development programme was initiated in early 1997 to encourage the application of clean coal technologies. Large circulating fluidised bed (CFB) power plants, pressurised CFB (PCFB) power plants, integrated gasification combined cycle (IGCC) power plants and coal liquefaction projects are currently being planned or implemented.

Exploration and development of China's oil and gas resources will be stepped up. Production is expected to increase, along with the share of oil and gas in total energy supply. Moreover, while making full use of existing power generating capacity, China is looking to develop hydroelectric power and build large-scale thermal power plants close to coalmines, reduce the number of small thermal power stations, and undertake a modest nuclear power development programme.

New and renewable energy is an important component of China's long-term development strategy. Where conditions permit, in cities or their surrounding areas, efforts will be made to develop wind power, solar heating, and solar photovoltaic power. The central government's Ride the Wind Power Programme aims to establish a wind technology manufacturing industry.

IMPROVING ENERGY EFFICIENCY

Improving energy efficiency will continue to be an energy policy priority in China. An adequate supply infrastructure is regarded as essential to this end. Ongoing efforts will be made to strengthen energy conservation legislation and regulations and to bolster enforcement. Energy efficiency standards and labelling will be implemented to eliminate the production of low efficiency products. Specific efforts will be aimed at transportation and energy-intensive industries such as ferrous metals, non-ferrous metals, building materials and chemicals.

ENVIRONMENTAL PROTECTION

China has very serious environmental pollution that needs to be more effectively controlled. In 2000, atmospheric emissions of sulphur dioxide reached 20 Mt while solid waste amounted to some 7 Bt. Acid rain affects approximately 30 percent of China's land area, and 70 percent of the rivers flowing through China's cities are polluted to some degree. Air quality meets environmental standards in only one-third of all cities.

Coal is the greatest source of energy and pollution in China. It is used for baseload electricity generation, but most coal-fired power plants have not installed flue gas desulphurisation, electrostatic precipitation or selective catalytic reduction equipment to control sulphur emissions. However, during the ninth five-year period from 1996 through 2000, closure of older, less-efficient coal plants and use of lower sulphur coal has limited air pollution to some degree.

During the tenth five year period from 2001 through 2005, environmental protection will be enhanced by improving the efficiency of electricity generation, increasing use of new and renewable energy, strictly enforcing environmental standards and aggressively adopting clean coal technology. It is estimated that if China could achieve the efficiency of the world's most developed economies in its power plants, its consumption of coal might decrease by 300 Mt per year.

WESTERN REGION DEVELOPMENT

Energy is used to achieve economic and social aims but it is also a tool to develop the resource-rich but underdeveloped western region. There are a number of major projects of strategic significance, such as the transmission of natural gas and electricity to the more developed eastern regions. The building and upgrading of power grids in urban and rural areas and work to complete an economy-wide network are also priorities. Measures to optimise energy industry structure, improve energy efficiency, intensify environmental protection, promote new and renewable energy development, and develop energy resources in the western region will have far-reaching impacts on economic reform in China and will help open its economy to the world.

NOTABLE ENERGY DEVELOPMENTS

WEST TO EAST NATURAL GAS PIPELINE PROJECT

To increase the use of cleaner energies like natural gas, China is planning to build a gas pipeline from the western Xinjiang Uygur Autonomous Region to eastern China. The pipeline is expected to be about 4,200 km long, from Talimu of Xinjiang to Shanghai, with a gas transmission capacity of 12 BCM in Phase I. The estimated cost of Phase I is RMB 120 billion. It is expected that the pipeline project will stimulate investment in gas exploration and development, lead to the establishment of distribution networks, and encourage increased gas use by industry. Companies and investors from all over the world have been invited by the Chinese government to participate in the investment, construction and management of this natural gas pipeline project, on which construction was expected to begin in mid-2002.

WEST TO EAST ELECTRICITY PROJECT

China has planned a project for the transportation of electricity from west to east. This project would include construction of both power plants and power transmission lines. In 2001, China's installed electricity generating capacity was 334 GW, and its power generation amounted to 1,465 TWh; in both respects, China had the second largest electricity industry in the world, after the United States. By the end of the tenth five-year plan in 2005, total installed capacity is expected to reach 390 GW, of which, hydro power will constitute 95 GW, thermal power 286 GW, nuclear power 8.7 GW, and new and renewable energy 1.2 GW. To accommodate growing generation and demand, the network of 500 kV high voltage transmission lines is expanding rapidly. In terms of construction of power plants, the five-year plan considers development on three distinct "roads": north, middle and south.

The "north road" refers to transfer of hydropower from the upper Yellow River, as well as thermal power from the Shanxi, Shaanxi and Inner Mongolia provinces, to the cities of Beijing and Tianjin and northern China more generally. During the tenth five-year period, it is anticipated that the north road will transfer the output from 5 GW of capacity to these areas, which will themselves install 8.5 GW of new capacity to help meet 10 GW of growth in capacity requirements. Construction of 2.6 GW of thermal power plants is going smoothly in Shanxi and Inner Mongolia.

Construction of 500 KV transmission lines from Hebei to Beijing and from Shanxi to Tianjin is also proceeding rapidly.

The "middle road" refers to the transfer of hydropower from the upper Yangtze River and Jinsha River to Shanghai and east China. During the tenth five-year period, new hydroelectric capacity of 18.2 GW at the Three Gorges project on the Yangtze River and 12 GW in the Jinsha River area will begin operation. It is expected that the middle road will transfer output from 3 GW of this new capacity to Guangdong province in the south and the output from another 3 GW to eastern China. Construction of the Three Gorges project is proceeding smoothly, and the first hydropower unit there will enter commercial operation in 2003. New 500 kV transmission lines are being built in rapid fashion from Three Gorges to east China, Guangdong province and Shanghai.

The "south road" mainly refers to transfer hydropower from the Wujiang River in Guizhou province and the Lanchan River in Yunnan and Guangxi provinces to Guangdong province. New installed hydro capacity of 1.8 GW in Guizhou, 1.2 GW in Yunnan and 4.2 GW in Guangxi entered service in 2000. Additional hydro capacity of 0.5 GW in Guizhou, 4.2 MW in Yunnan and 2.4 GW in Guangxi was expected to enter service in 2002. New 500 kV transmission lines are being built from Guizhou to Guangdong to help move the output from this capacity eastward.

RESTRUCTURING THE ELECTRIC POWER INDUSTRY

Power industry structural reform is a priority in China. After decades of economy-wide planning and monopolistic management, it may be difficult to introduce market-based competition into the electricity industry. However, with rapid growth of the power sector and continuous entry of new market participants, competition may gradually take hold. It is anticipated that the operation of power plants and transmission grids will be unbundled and that competitive bidding for generation by independent power producers will be instituted.

SALE OF SHARES IN STATE OWNED OIL COMPANIES

As a part of the restructuring programme of state-owned enterprises, the Chinese government has offered foreign investors the opportunity to purchase shares in China's major oil companies. The largest state-owned petroleum company, China National Petroleum Corporation (CNPC) established a subsidiary company, PetroChina Company Limited. In April 2000, PetroChina made a successful IPO (Initial Public Offering) of its shares in both Hong Kong and New York and raised capital totalling US$ 2.89 billion. Based on proven hydrocarbon reserves in 1998, PetroChina is the world's fourth largest publicly traded oil and gas company. China's second largest oil company, SINOPEC, has established a subsidiary company – the China Petrochemical Corporation. On 19 October 2000, the China Petrochemical Corporation was listed on the Hong Kong, New York and London stock exchanges, the first Chinese enterprise listed on three overseas markets simultaneously. Further, a subsidiary of China's third largest oil company, CNOOC, was listed on the New York stock and Hong Kong exchanges in February 2001.

WHITE PAPER ON NEW AND RENEWABLE ENERGY

The State Development Planning Commission (SDPC) issued the new edition of its white paper *New and Renewable Energy of China* in April 2000. The State Economic Trade Commission (SETC) also has a five-year plan and ten-year planning perspective on renewables. These papers are among the many efforts by the Chinese government to promote new and renewable energy in China. They summarise China's energy supply and demand situation and the need for renewable energy. They also provide detailed information and policies under consideration by the Chinese government for various technologies, such as wind power, solar thermal, solar PV, ocean energy, and biomass. The SDPC paper also outlines a national renewable programme which is now being implemented.

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HONG KONG, CHINA

INTRODUCTION

Hong Kong, China is a city-economy of some 7 million people on the coast of southern China. Since 1997, it has been a Special Administrative Region (SAR) of the People's Republic of China. All energy consumed in Hong Kong is imported as the city is completely without indigenous oil, gas or coal resources. The energy sector consists of investor-owned electricity and gas utility services.

Hong Kong, China is a modern economy with a high GDP per capita of US$ 24,016 (1995 US$ at PPP) in 2000. The service sector is responsible for 85 percent of GDP. In the last few decades, firms in Hong Kong, China have been moving low value-added work offshore, and have concentrated on high-value, technology-based markets. This process of economic adjustment has resulted in a significant increase in trading and financial and other service activities. Hong Kong, China is a principal service centre, both in the Asia-Pacific region and globally.

Table 11 Key data and economic profile (2000)

Key data		Energy reserves	
Area (sq. km)	1,097	Oil (Proven)	0
Population (million)	6.80	Gas	0
GDP Billion US$ (1995 US$ at PPP)	163.24	Coal (Recoverable)	0
GDP per capita (1995 US$ at PPP)	24,016		

Source: Energy Data and Modelling Centre, IEEJ.

ENERGY DEMAND AND SUPPLY

PRIMARY ENERGY SUPPLY

In 2000, total primary energy supply in Hong Kong was 15,110 ktoe. Of this total, 54 percent was oil, 27 percent coal and 13 percent gas. Electricity imports from China accounted for the remaining 5 percent. Hong Kong has no domestic energy reserves or petroleum refineries and imports all of its primary energy needs through it generates some electricity. In 1995, Hong Kong began importing natural gas by pipeline from the South China Sea offshore gas field Yacheng.

Hong Kong, China had a total installed electricity generating capacity of 11,568 MW in 2000. This includes 70 percent of the capacity of units 1 and 2 of the Guangdong Nuclear Power Station at Daya Bay and 50 percent of the Guangzhou Pumped Storage Power Station. Power from these facilities is imported from China through CLP (China Light and Power Holding) power transmission connections to Guangdong provincial grid. Locally generated power is all thermally fired.

FINAL ENERGY CONSUMPTION

Total final energy consumption in Hong Kong reached 11,225 ktoe in 2000. The bulk of energy was used in the transportation sector (54 percent), followed by the residential/commercial sector (31 percent) and the industrial sector (15 percent). With the dominance of transport, the most important end use fuel was petroleum, accounting for 67 percent of energy use. Electricity made up 28 percent of end-use consumption, while gas accounted for only 5 percent.

Table 12 Energy supply & consumption (2000)

Total Primary Energy Supply	**(ktoe)**	**Total Final Energy Consumption**	**(ktoe)**	**Power Generation***	**(GWh)**
Indigenous Production	0	Industry Sector	1,716	Total	31,329
Net Imports & Other	15,110	Transport Sector	6,071	Thermal	31,329
TPES	15,110	Other Sectors	3,438	Hydro	0
Coal	4,125	TFEC	11,225	Nuclear	0
Oil	8,203	Coal	4	Others	0
Gas	2,007	Oil	7,539		
Others	776	Gas	560		
		Electricity & Others	3,121		

Source: Energy Data and Modelling Center, IEEJ (see http://www.ieej.or.jp/apec/database/selecttable.html)

* Total does not include electricity generated by hydro and nuclear facilities owned by HKC but located in China.

Gas is supplied for domestic, commercial and industrial uses in two main forms. Town gas is distributed by the Hong Kong and China Gas Company Limited; liquefied petroleum gas (LPG) is supplied by oil companies. In 2000, town gas accounted for 73 percent of gas use in these sectors in energy terms. In the electricity sector, Hong Kong opened its first gas-fired power plant in 1996.

POLICY OVERVIEW

The government of the Hong Kong Special Administrative Region (SAR) pursues two key energy policy objectives. The first is to ensure that the energy needs of the community are met safely, efficiently and at reasonable prices. The second is to minimise the environmental impact of energy production and promote the efficient use and conservation of energy.

In keeping with Hong Kong, China's free market economic philosophy, the SAR intervenes only when necessary to safeguard the interests of consumers, ensure public safety and protect the environment. Hong Kong, China works with the power, oil and gas companies to maintain strategic reserves of coal, diesel and naphtha. It monitors the performance of the power companies through the Scheme of Control Agreements. The government has entered into an Information and Consultation Agreement with the Hong Kong and the China Gas Company Ltd to make the town gas tariff adjustment mechanism more transparent. In consultation with the power companies, the government also promotes energy efficiency and energy saving measures.

To help monitor the energy situation, Hong Kong, China has developed an energy end-use database and forecasting model. The database will provide useful insight into the energy supply and demand situation, including energy consumption patterns and trends and energy use characteristics of the individual sectors and sub-sectors. A basic data set is publicly available on the Internet.

The SAR is currently studying a consultant report on the feasibility of adopting a common carrier system for the transmission and distribution of natural gas. It is also studying a report on the state of interconnection and competition in the electricity sector.

The Electricity Ordinance and the Gas Safety Ordinance regulate the safe supply of electricity and gas. Among other things, these ordinances cover the registration of generating facilities, workers and contractors for electrical and gas installations, wiring and gas installation standards and safe distribution and use of electricity and gas. Most provisions of the Electrical Product (Safety) Regulation, which regulates the safety of household electrical products, came into effect in May 1998.

NOTABLE ENERGY DEVELOPMENTS

BUILDING ENERGY CODES AND APPLIANCE EFFICIENCY LABELS

The government of the Hong Kong Special Administrative Region has promulgated Building Energy Codes (BECs) through the 1998 Hong Kong Energy Efficiency Registration Scheme for Buildings. The scheme covers lighting, air-conditioning, electrical and lift & escalator installations. There are over 60 buildings registered as at mid 2002. The government commissioned a consultancy study on performance-based BECs, to be completed by the end of 2002. The study uses a total-energy-budget approach and aims to improve BECs' adaptation to innovative design and technology.

The government has issued labels for more than 1,400 appliance models including refrigerators, room coolers, washing machines, electric clothes dryers, compact fluorescent lamps, electric storage water heaters, photocopiers, electric rice-cookers and multifunction office devices under voluntary energy efficiency labelling schemes as of July 2002. A labelling scheme was launched for petrol-fuelled passenger cars in February 2002 to raise public awareness in the energy efficiency of vehicles. Voluntary efficiency labels were extended to household dehumidifiers and laser printers in late 2002.

DEMAND SIDE MANAGEMENT AND ENERGY AUDITS

As for demand side management, the power companies continue to implement their heating, ventilating and air-conditioning rebate programmes for non-residential customers. The government has completed a review of the need for extending the power companies' non-residential rebate programmes to residential customers. Based on this review, the government has concluded that there is no such need as the awareness of energy efficiency among residential customers is high.

The government has implemented an Energy Audit Programme in selected government buildings since 1993. As of March 2002, energy audits had been performed in 154 major government buildings with the greatest potential for energy savings. Pilot tests on innovative energy efficient equipment related to lighting, air conditioning and vertical transportation have also been carried out in government buildings since 1999. The tests have been very successful, with substantial energy savings achieved. Equipment used includes lamps for offices and sports halls, a new drive system for lifts, evaporative cooling systems, heat pumps, intelligent air-conditioning, and a digital lighting control system with occupancy and daylight sensors.

ENERGY END-USE DATABASE

The government has developed an energy end-use database and an energy supply and demand forecasting model for Hong Kong. The database provides useful insight into energy consumption patterns of different sectors, sub-sectors and end uses. The forecasting model projects future energy supply and demand and primary energy mix. The Household Energy Consumption Study was completed in January 2002 to track patterns of energy use and derives energy consumption indices for key household appliances. The Transport Energy Consumption Survey was commissioned in March 2002 to develop energy use intensities for public non-franchised buses, private light buses, heavy goods vehicles, and tractor and non-tractor medium-weight goods vehicles.

ALTERNATIVE FUEL VEHICLES

The government has provided an incentive scheme to encourage owners of existing diesel public and private light buses to replace their vehicles early with ones that run on LPG or electricity. A program to replace all 18,000 diesel taxis in the Territory with LPG taxis by 2005 had reached 87 percent of its goal by late 2002. The Electrical and Mechanical Services Department (EMSD) is advising the government on incentives to motivate switching to vehicles that use clean alternative fuels, as well as on how to develop supporting infrastructure for the use of such fuels. A local gas supply company is conducting trial runs on natural gas vehicles for its service vehicle fleet.

RENEWABLE AND CLEAN ENERGY

The government commissioned a consultancy study to investigate the viability of using new and renewable energy technologies in Hong Kong. It will also examine associated institutional, legal, regulatory and financial issues. The study, to be completed in early 2004, has already identified a number of new and renewable energy technologies as likely options for wide scale local adoption. A pilot project to install building-integrated photovoltaic panels in an existing high-rise government building is scheduled for completion by early 2003. Plans have already been made to install about 885 kW of photovoltaic panels in eleven government projects over the next three years.

WATER-COOLED AIR CONDITIONING SYSTEMS (WACS)

The government is conducting three consultancy studies on wider use of water-cooled air conditioning systems, recognising their energy-saving potential. One study is on the territory-wide implementation of WACS and the other two are on the implementation of district cooling systems in a new development area and an existing developed area. All three studies should be completed by mid-2003, and the government will consider their findings and recommendations.

ENERGY CONSUMPTION INDICATORS AND BENCHMARKS

A consultancy study on the development of energy consumption indicators and benchmarks for selected groups in the commercial and transport sectors will soon be completed. The study will establish energy consumption indicators and benchmarks against which targeted groups can set improvement targets. A benchmarking tool will also be made available to enable individual operators to benchmark their energy consumption with others in the same group. The study and benchmarking tool were to be made available on the Electrical and Mechanical Services Dept's website in late 2002.

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INDONESIA

INTRODUCTION

Indonesia is an archipelago comprised of around 17,500 large and small islands near the equator, with a total land area of about 2 million square kilometres. The population is about 210 million, the majority of whom reside in Java, one of the five main islands.

In 2000, real gross domestic product (GDP) was US$587.6 billion and per capita GDP was about US$2,793 (both in 1995 US$ at PPP). Economic growth slowed to 3.1 percent in 2001 from 4.8 percent in 2000 in response to the global economic slowdown, which reduced demand for the economy's exports.

Mining activities, especially of petroleum and tin, have expanded since 1970. Fossil energy resources, namely oil, natural gas and coal, play important roles in the economy as industrial raw material and foreign exchange earners. In 2000, Indonesia possessed oil reserves of around 795 MCM, natural gas reserves of around 2,047 BCM and coal reserves of 5,220 Mt. Although declining in share, agriculture still plays a dominant role in the economy.

Table 13 Key data and economic profile (2000)

Key data		Energy reserves*	
Area (sq. km)	1,937,179	Oil	795 MCM
Population (million)	210.42	Gas	2,047 BCM
GDP Billion US$ (1995 US$ at PPP)	587.61	Coal	5,220 Mt
GDP per capita (1995 US$ at PPP)	2,793		

Source: Energy Data and Modelling Centre, IEEJ.

*Proved reserves at the end of 2000 from The BP Statistical Review.

ENERGY DEMAND AND SUPPLY

PRIMARY ENERGY SUPPLY

In 2000, total primary energy supply was 101,236 ktoe. Of this total, 50 percent was oil, 34 percent gas, 11 percent coal, 4 percent geothermal and 1 percent from hydropower. Indonesia is a large net energy exporter, selling about half of the oil, gas and coal it produces.

Most of Indonesia's proven oil reserve base is located onshore in the Duri and Minas fields in central Sumatra. Other significant production fields are located in offshore northwestern Java, East Kalimantan and the South China Sea. During the last decade, crude oil production in Indonesia ranged between 1.3 and 1.4 million bbl/d. In recent years these fields have started to mature leading to declines in production. Indonesia also produces around 235,000 bbl/d of natural gas liquids and lease condensate annually although this production is not included in its OPEC quota (which was 1.125 million bbl/d OPEC beginning 1 January 2002.

In 2000, Indonesia produced around 60,500 ktoe of natural gas, of which around 60 percent was exported as LNG. Of the LNG, around two-thirds went to Japan, 23 percent to Korea and 10 percent to Chinese Taipei. Considering the availability of natural gas in Indonesia, its use is relatively under-developed. Almost all domestic gas consumption is for industry (such as fertilizer production) and electricity generation.

Of the 5,220 million tonnes of recoverable coal reserves in Indonesia, about 85 percent are lignite and 15 percent are anthracite. Approximately about two-thirds of Indonesia's coal reserves are located in Sumatra, and the rest are found in Kalimantan, West Java and Sulawesi. Most coal produced is exported to Japan, South Korea and Chinese Taipei. Indonesia has plans to double its coal production, viewing other economies in East Asia and India as markets of high potential.

Indonesia produced 122,800 GWh of electricity in 2000. It has an estimated installed generating capacity of 21.4 GW. Of its total electricity production, 88 percent came from thermal sources, 8 percent from hydropower and 4 percent from geothermal plants.

Table 14 Energy supply & consumption (2000)

Total Primary Energy Supply	**(ktoe)**	**Total Final Energy Consumption**	**(ktoe)**	**Power Generation**	**(GWh)**
Indigenous Production	183,995	Industry Sector	25,170	Total	122,800
Net Imports & Other	-82,759	Transport Sector	21,452	Thermal	107,909
TPES	101,236	Other Sectors	19,459	Hydro	10,022
Coal	10,956	TFEC	66,082	Nuclear	0
Oil	51,023	Coal	2,053	Others	4,869
Gas	34,048	Oil	44,061		
Others	5,210	Gas	8,089		
		Electricity & Others	11,878		

Source: Energy Data and Modelling Center, IEEJ (see http://www.ieej.or.jp/apec/database/selecttable.html)

FINAL ENERGY CONSUMPTION

Indonesia's final energy consumption grew about 9 percent from 60,741 ktoe in 1999 to 66,082 ktoe in 2000. The most important end use fuel was oil, accounting for 67 percent of consumption, followed by electricity at 18 percent, gas at 12 percent and coal at 3 percent. Non-commercial biomass, an important source of energy in the residential sector, is not currently taken into account due to difficulties in measuring consumption levels. In 2000, industry surpassed transport as the largest consuming end-use sector. Industry accounted for 39 percent of final energy consumption, transport for 32 percent, and other sectors for 29 percent.

POLICY OVERVIEW

As part of efforts to reduce dependence on oil in the energy mix and free more of it for export, Indonesia's energy policy goals include:

- Gradually shifting from a mono-energy economy to a poly-energy economy by using relatively less oil and more of other domestic resources such as coal and gas;
- Assuring the availability of energy for domestic markets at reasonable prices;
- Ensuring that energy resources continue to contribute to the balance of payments and public revenues;
- Postponing the day that Indonesia becomes a net oil importer by extending reserves, diversifying sources of supply, and promoting energy conservation;
- Creating a climate that encourages resource exploration and development;

- Improving national resilience; and
- Protecting the environment.

Through its policy of energy use diversification, Indonesia has reduced the oil share of the total commercial energy consumption from around 90 percent in 1970 to about 57 percent in 2000. On the other hand, the share of natural gas in the energy mix has increased substantially from 5 percent to 25 percent in the past three decades. However, due to rapid energy consumption growth, the volume of oil consumed continues to increase.

OIL AND GAS

Oil and gas industry objectives are focussed on:

- Maintaining oil production at current levels while maintaining an attractive investment climate for potential investors;
- Maintaining Indonesia's role as the world's largest LNG exporter together with increasing domestic gas utilisation supported by integrated pipeline development;
- Developing new refineries to meet domestic demand;
- Increasing oil and gas reserves and production potential;
- Promoting energy diversification and conservation by utilising gas in an effort to delay the time when Indonesia becomes a net importer of oil; and
- Restructuring state-owned companies and business units while improving oil legislation and regulations.

The Indonesian government is currently formulating a programme to remove the price subsidies on oil and gas. It is hoped that some restructuring initiatives and improved efficiencies can be used to mitigate the price increases that will result.

NOTABLE RECENT ENERGY DEVELOPMENTS

OIL INDUSTRY

In 2001, nine new production-sharing contracts (PSCs) were signed with a goal to increase production. New explorations sites have been offered for tender in the, as yet unproven, eastern regions. In the next year or so, three major new oil projects are expected to commence production. However, their combined incremental production may not increase total output significantly as other maturing fields' production declines. APERC projects that Indonesia could become a net importer of oil as early as 2011.

REFORMS

Legislation passed in October 2001 will remove Pertamina's monopoly on upstream oil development within two years. Previously, Pertamina was required to be included in all PSCs. Within four years, its sole right of petroleum products distribution will also be eliminated.

Under the new reforms, Indonesia's Ministry of Mines and Energy takes over the role of awarding and supervising PSCs. Foreign firms are freed from some compliance requirements. However, the devolution of some decision-making powers to regional governments has given them some power to tax company profits.

There has been subsidies reduction in domestic consumption in a bid to restrain growth in domestic consumption and to reduce government's budget deficit.

NATURAL GAS INDUSTRY

In 2001, a joint venture consisting of Conoco, Gulf Indonesia Resources and Pertamina started exporting 32 billion standard cubic feet (Bcf) of piped natural gas to Singapore from the Natuna fields in the South China Sea. Under an agreement made in 1999, Pertamina and Singapore-based Sembawang Gas (SembGas) will pipe 2.6 trillion cubic feet from Indonesia to Singapore (Jurong Island) over a 22-year period in which revenues form the contract could reach about $8 billion.

In 2001, the electric power producer Perusahaan Listrik Negara (PLN), Indonesia's largest consumer, reduced natural gas consumption due to declining production from BP's offshore Kangean field. PLN anticipates that gas demand will exceed supply after 2005. By then, the government plans to eliminate the fuel oil subsidy, allowing the gas price to be more competitive.

Nitrogenous fertilizer plants are the second largest domestic consumers of natural gas. Their consumption declined about 15 percent in 2001 from 214.4 Bcf in 2000 due to a four-month suspension of natural gas production at Exxon Mobil's Arun fields. Gas consumption by residential and commercial entities, however, surged by 38 percent to 86.3 Bcf in 2001 from 62.6 Bcf in 2000. Growth in gas use was particularly strong in areas of Surabaya and Jakarta.

GAS SUPPLY DEAL

The government has been negotiating to discontinue BP's exclusive rights to supply 320 million cubic feet per day (Mcf/d) of gas from the Kangean field to consumers in East Java. Depletion of natural gas at the Kangean field will soon create a gap between BP's supply and consumers' demand. The gap will be hard to close due to the take-or-pay clause in BP's current contract that hinders potential new suppliers. BP, which can produce only 260 Mcf/d, has decided to forego some of its initial supply rights. Having done so, BP hopes to extend its Kangean PSC that is due to expire in 2010. Amerada Hess has signed a memorandum of understanding (MoU) with Pertamina to supply 150 Mcf/d from Ujung Pangkah by 2004. Once the government agrees to extend the contract, BP will start developing the Terang and Sirasun fields at a cost of $400 million.

By the end of this decade, gas demand is expected to grow sharply to more than 700 Mcf/d. Indonesia will have to accelerate its development projects in order to meet the future demand.

PNG DEVELOPMENT

Petronas, the Malaysian state petroleum company, is the strategic partner selected by PGN, the Indonesian state gas pipeline company, for construction of a $470 million pipeline network. PGN's subsidiary, TransCo I, will construct a gas pipeline from South Sumatra to Singapore delivering US$9 billion worth of natural gas over a twenty-two year period. The Petronas-led consortium that includes Singapore Petroleum Co., Talisman Energy Inc and Gulf Indonesia Resources will invest around a total of $250 million for a 25 to 40 percent equity stake in TransCo I. The consortium will become Indonesia's leading independent oil and gas producer by 2005.

An MoU was signed in April 2001 between Gulf Indonesia Resources, Pertamina, and PGN for supply of natural gas to Batam Island. Under the MoU, Gulf will supply up to 50 Mcf/d of natural gas to PGN, which PGN will deliver to power plants operated by PLN, commercial customers and domestic industries. The parties were to finalise an agreement in the second half of 2002.

POWER SECTOR

Indonesia has an estimated electricity generation capacity of around 21.4 GW of which 84 percent is thermal, 14 percent hydropower, and 2 percent geothermal. Indonesia's plans to expand power supply by opening its market to independent power producers (IPPs) were slowed by the Asian financial crisis. For instance, a 1,230 MW coal-fired plant, Paiton I was completed in 1999 by a consortium led by Edison Mission Energy, General Electric, and Mitsui but was not activated. Finally, in November 2000, the consortium and PLN, came to a settlement which included a downward tariff adjustment and a long-term payment scheme. The 1,320 MW Tanjung Jati-B thermal plant in Central Java, an abandoned construction project, was due to recommence construction, by Sumitomo Corporation, before the end of 2002.

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JAPAN

INTRODUCTION

Japan is small geographically, comprising just 377,800 square kilometres, which is equivalent to the size of California, USA. Despite its land size, it is the world's second largest economy after the USA. Japan's real gross domestic product (GDP) in 2000 was about US$ 3,263 billion (1995 US$ at PPP). With a population of 126.9 million people, per capita income is high at US$ 25,716.

Up to the early 1990s, Japan enjoyed a long period of rapid socio-economic development. In 1992, however, Japan's economy entered a decade of stagnation. GDP grew only 0.2 percent in 1999 and 0.9 percent in 2000 after shrinking 2.5 percent in 1998. The unemployment rate reached 5.2 percent in 2001.

Japan possesses few indigenous energy resources and therefore imports almost all the crude oil, natural gas and uranium it needs to sustain economic activity. In 2000, proven energy reserves included around 9 MCM of oil, 40 BCM of natural gas and 785 Mt of coal.

Table 15 Key data and economic profile (2000)

Key data		Energy reserves*	
Area (sq. km)	377,800*	Oil (Proven)	9.4 MCM
Population (million)	126.87	Gas	39.6 BCM
GDP Billion US$ (1995 US$ at PPP)	3,262.63	Coal (Recoverable)	785 Mt
GDP per capita (1995 US$ at PPP)	25,716		

Source: Energy Data and Modelling Center, IEEJ.

*Ministry of Construction, Japan 2000.

ENERGY DEMAND AND SUPPLY

PRIMARY ENERGY SUPPLY

Japan's total primary energy supply (TPES) was 509 Mtoe in 2000. By fuel, oil represented the largest share at 50 percent, the coal share was second at 19 percent, followed by nuclear at 16 percent, natural gas at 13 percent, hydro at 1 percent and NRE, including geothermal, wind and others at 1 percent. In 2000, 80 percent of total primary energy was imported. Imports account for almost 100 percent of oil consumption, 98 percent of coal demand and 97 percent of gas use. Total primary energy supply fell by 0.3 percent in 2000 after increasing 2.5 percent in 1999.

Japan is the world's second largest oil consumer after the United States, almost all of it imported. The bulk of these imports (80 percent in 2000) come from OPEC economies such as the United Arab Emirates (UAE), Saudi Arabia, Kuwait, Qatar and Iran. In 2000 primary oil supply was 253 Mtoe, a decline of 4.2 percent from the previous year.

Japan is endowed with only limited coal reserves at 785 million tonnes. The small amount of coal production had been heavily subsidised until 30 January 2002 when Japan's last coal mine in Kushiro, eastern Hokkaido was closed. Japan is the world's largest coal importer of steam coal for power generation, pulp and paper and cement production and coking coal for steel production. Japan's main steam coal suppliers are Australia, China, the United States, South Africa, Canada and Russia. Coking coal is imported from Australia, Canada, the United States China, Russia and South

Africa. In 2000 primary coal supply was 94 Mtoe or 7.5 percent higher than the previous year reflecting the rapid growth of steam coal demand for power generation[2].

Japan possesses limited natural gas resources. Indigenous proven reserves stand at 40 BCM, located in Niigata, Chiba and Nagano prefectures. Domestic demand is met almost totally by imports of LNG[3] which come mostly from Indonesia (34 percent of imports in 2000), Malaysia (20 percent) and Brunei. Natural gas is mainly used for electricity generation (69 percent of total usage in 2000), followed by reticulated city gas (29 percent) and feedstock for petrochemical plants (1 percent). In 2000, primary natural gas supply was 65 Mtoe or an increase of 3.9 percent over the previous year. Both power and city gas sectors are responsible for the natural gas demand growth.

Japan generated 1,074 TWh of electricity from 259 GW of installed capacity in 2000. The generation fuel breakdown was: thermal (coal, natural gas and oil) at 61 percent, nuclear at 30 percent, hydro at 8 percent and geothermal, solar and wind comprising the remainder. Due to increased investment in nuclear and more recently, gas-fired capacity in the power sector, the "oil dependence ratio" (share of crude oil and oil products in total primary supply) fell to 50 percent, its lowest level since 1963.

Table 16 Energy supply & consumption (2000)

Total Primary Energy Supply	**(ktoe)**	**Total Final Energy Consumption**	**(ktoe)**	**Power Generation**	**(GWh)**
Indigenous Production	102,112	Industry Sector	162,700	Total	1,073,840
Net Imports & Other	407,365	Transport Sector	87,872	Thermal	659,088
TPES	509,477	Other Sectors	112,644	Hydro	86,959
Coal	94,296	TFEC	363,216	Nuclear	319,756
Oil	252,956	Coal	40,718	Others	8,037
Gas	64,732	Oil	212,895		
Others	97,494	Gas	22,361		
		Electricity & Others	87,242		

Source: Energy Data and Modelling Center, IEEJ (see http://www.ieej.or.jp/apec/database/selecttable.html)

After the first oil crisis in 1973, Japan invested heavily in nuclear power. Energy production from nuclear sources increased dramatically from 1973 to 1998, averaging 15.7 percent per year. In 1999 primary nuclear supply accounted for 83 Mtoe or 318 TWh of output, representing 16 percent of the total electricity supply. Two new nuclear units, Kashiwazaki Kariwa #7 in Niigata prefecture and Genkai #4 in Saga prefecture, started operation in July 1997. The utilisation factor for all nuclear units was about 80 percent in both 1999 and 2000. In 2000, 51 units were in operation and Japan ranks third worldwide in installed nuclear capacity after the United States and France. However, during the past few years, public opposition to nuclear development has increased due to a series of accidents.

2 Rapid growth in demand for steam coal reflects its cost competitiveness against petroleum products. In 2000, the price of crude oil soared by 67 percent to 28$/bbl, while the price of coal remained stable. Energy security is also an important factor in shifting power generation demand for input fuel away from petroleum products.

3 In 2000, LNG imports to Japan comprised 63.7 percent of total world LNG trade.

FINAL ENERGY CONSUMPTION

In 2000, Japan's final energy consumption was 363 Mtoe, or 0.93 percent higher than the previous year. The industrial sector consumed 45 percent of the total, followed by the residential/commercial sector at 26 percent and the transportation sector at 24 percent. By fuel source, petroleum products accounted for 59 percent of final energy consumption, followed by electricity at 23 percent, coal at 11 percent and city gas at 6 percent.

Output in the industrial sector increased by 4.6 percent in 2000, a higher growth than in 1999 at 3.6 percent. Energy consumption by manufacturing industries, which account for 91 percent of energy consumed in the industrial sector, increased by 1.4 percent in 2000 reflecting the steady increase in production of crude steel production and pulp and paper. Energy consumption by non-manufacturing industries, which accounted for 9 percent of energy consumption in the industrial sector, increased by 0.4 percent in 2000.

In 2000, the residential/commercial sector electricity accounted for 46 percent of total energy consumed, followed by petroleum products at 37 percent, city gas at 14 percent, solar heat at 1 percent and coal at 1 percent. The energy consumption of the residential/commercial sector grew by 2.7 percent. In the residential sector, energy demand increased by 3.2 percent in 2000 because power demand for air-conditioning increased as a result of the hot summer in Japan. In the commercial sector, floor space additions translated into a 1.0 percent increase in energy consumption in 2000.

In the transport sector, passengers accounted for 64 percent of energy consumption in 2000 and the freight sector was responsible for 36 percent. In 2000, energy consumption in the transportation sector fell by 6.5 percent due to the ongoing recession that dampened demand for transportation services.

POLICY OVERVIEW

The Ministry of Economy Trade and Industry (METI) is responsible for formulating energy policy. Within METI, the Agency of Natural Resources and Energy (ANRE) is responsible for rational development of mineral resources, securing a stable supply of energy, promoting efficient energy use and regulating electric power and other energy industries. Other government departments involved in the energy sector include the Science and Technology Agency, responsible for nuclear safety, and research and development, and the Ministry of Foreign Affairs responsible for formulating international policy.

The principal goal of Japanese energy policy aims at achieving the 3Es, namely energy security, economic growth and environmental protection. The 3Es are to be accomplished simultaneously, using a balanced approach and if necessary, with trade-offs between the objectives. Securing stable energy supply sources, using energy efficiently, introducing new and renewable energy sources and further strengthening nuclear utilisation will be important in achieving the 3Es.

Several key energy issues currently face Japan. One key issue is securing stable energy supplies to satisfy growing energy demand in the residential/commercial and transportation sectors where there exists a low rate of energy self-sufficiency. A second issue is how to meet the Kyoto Protocol commitment, negotiated at COP3, to reduce greenhouse gas (GHG) emissions to 6 percent below 1990 levels by the period 2008 to 2012. A third issue is how Japanese industry, including the energy sector, can best restructure to improve its economic efficiency and thereby increase its domestic and international competitiveness.

OIL

Given the importance of oil in Japan's energy mix and its substantial dependence on imported oil from the Middle East, the Japanese government has taken measures to secure adequate energy supplies including developing an integrated domestic oil industry with upstream and downstream sectors. The following are the specific measures that the Japanese government has undertaken:

- *Promotion of Oil Exploration and Production:* Japan has promoted oil exploration both at home and abroad. The oil industry actively participates in projects abroad with the financial and technical assistance of the government-funded Japan National Oil Corporation (JNOC).
- *Possession of Stockpiles:* Private oil companies are subject to the Petroleum Stockpiling Law, which requires them to stockpile oil in case of emergencies and unexpected oil supply disruption. The government also holds stockpiles through JNOC.
- *Strengthening Relations with Oil Producing Economies:* Japan has promoted mutual understanding with oil producing economies and technological cooperation through various joint projects managed by the Petroleum Energy Center, Japan Cooperation Center, Petroleum and other organisations. These projects include training programmes, information exchanges and joint research projects.

The Provisional Measures Law on the Importation of Specific Petroleum Refined Products (PLISPP) expired in March 1996 and was not renewed. The PLISPP designated specific refining facilities as the approved importers of specified oil products such as gasoline, kerosene, and diesel, and made them responsible for securing stable supplies. This task is now open to anyone so long as stockpiling requirements and quality standards are met. There have also been recent changes to the pricing system for petroleum products. These changes have encouraged trading firms such as the National Federation of Agricultural Cooperative Associations and major dealers to import petroleum products directly. Fierce competition in the oil market has led to mergers and reorganisation among the incumbent firms.

NATURAL GAS

Since 1969, when Japan began importing LNG from Alaska, natural gas consumption has grown rapidly. Natural gas accounted for 13 percent of total primary energy in 2000. Natural gas use is expected to play an important role in mitigating greenhouse gas emissions as well as improving air quality. In anticipation of further natural gas utilisation, the Japanese government has tried to accelerate the development of natural gas resources. To secure a stable supply of natural gas, the Japan National Oil Corporation Law was revised in June 1994 to allow JNOC to provide capital and loan guarantees to Japanese companies that are developing gas fields or LNG projects.

In 1995, the Gas Utilities Industry Law was amended for large industrial customers with contracted amounts of more than 2 MCM per year. Through three amendments to the law, these customers were given the right to negotiate prices directly with suppliers. First, gas utilities were allowed to compete outside their service areas. Second, non-city gas suppliers were allowed to supply large industrial customers. Third, gas tariffs were made free of regulation in principle. These amendments were meant to benefit consumers and make utilities more competitive.

The gas law was amended again in 1999 to extend competition to contracted amounts of more than 1 MCM per year and to waive the requirement for METI approval of gas tariff decreases. These changes were intended to minimise government involvement in the gas market and procure lower prices for consumers.

ELECTRICITY

In 1995, the Electricity Utilities Industry Law, the main legislation covering the electricity industry, was amended. The changes were meant to address global energy sector reform, comparatively high electricity tariffs in Japan and deteriorating load factors. The amendments permitted the entry of independent power producers (IPPs) into the Japanese electricity market. The 10 major electric utilities, each of which holds a regional monopoly, were given the right to accept tenders for IPP investment in generation to cover short-term thermal power requirements.

In 1999, the Electric Utilities Industry Law was amended again to allow the partial liberalisation of retail sales starting in March 2000. Eligible customers, either high voltage users (20kV) or users with contracted demand over 2,000 kW, can now freely contract with power suppliers, including IPPs.

NUCLEAR ENERGY

According to a declaration on reducing oil dependence issued by the Japanese government in September 1998, nuclear will play a significant role in energy supply because of its reliability, economic viability and low CO_2 emissions. The Japanese electricity supply and demand plan developed in 1998 projected nuclear expanding to 4,780 TWh, with an additional 16 to 20 units by 2010. To promote this strategy, the Japanese government is engaged in promoting a better public understanding of nuclear power, establishing a nuclear fuel cycle, ensuring the safety of plants and improving plant capability and reliability.

To ensure the effective use of uranium resources and proper radioactive waste management, Japan has established nuclear fuel cycle facilities as part of its nuclear energy programme. There are three nuclear fuel cycle facilities in operation as well as one under construction in Rokkasho Mura, Aomori prefecture. Research and development of the Fast Breeder Reactor (FBR), a technology that consumes less uranium than conventional reactors, is currently taking place.

Public opposition to nuclear development is growing due to recent nuclear incidents. One such event took place on September 30 1999 at an uranium processing plant in Tokaimura, Ibaraki prefecture, when radiation levels rose to critical in part of the plant. This accident highlighted the need to strengthen emergency counter measures and to clarify the responsibilities of nuclear power operators in the area of disaster prevention. The special Law for Nuclear Disaster Measures was recently passed to address concerns raised by the accident.

ENVIRONMENT

In recognition of its commitments under the Kyoto Protocol to reduce GHG emissions 6 percent below the 1990 level during the first commitment period (2008 through 2012), Japan established the Outline for Promotion of Efforts to Prevent Global Warming in June 1998. In October 1998, Japan passed the Law for Promotion of Efforts to Prevent Global Warming.

The Energy Supply and Demand Subcommittee of the Advisory Committee for Energy produced a Long-Term Energy Supply and Demand Outlook in June 1998. The outlook projected that energy consumption in 2010 would remain almost unchanged compared with 1996 levels through the use of the following measures: (1) Keidanren's voluntary action plan, (2) equipment energy efficiency improvements through the "top-runner" programme under the Revised Law Concerning the Rational Use of Energy, and (3) influencing consumer behaviour through greater emphasis on energy conservation. Promotion of nuclear power is included in the policy as a measure to mitigate GHG emissions.

NOTABLE ENERGY DEVELOPMENTS

REGULATORY REFORM

Major structural reforms were implemented in 1999 in the oil, gas and electricity sectors to increase competition in domestic energy markets. In 2002, the current laws will be reviewed, and if deemed prudent, additional measures may be implemented.

REVISIONS TO LONG-TERM ENERGY SUPPLY AND DEMAND OUTLOOK

Under the 1997 Kyoto Protocol, Japan agreed to reduce its GHG emissions to 6 percent below 1990 levels by the first commitment period (2008 to 2012). In June 1998, the Advisory Committee for Energy released the "Long term Energy Supply and Demand Outlook" outlining how Japan would achieve these cuts. However, by 1999, due to changing circumstances, it was argued that some of the measures specified in the report were unrealistic and that revisions to the Outlook were necessary.

In June 2001, the Japanese government released the revised version of its "Long term Energy Supply and Demand Outlook". A key change was the scaling back of its nuclear power development plan. To meet the Kyoto targets, the previous Outlook required the construction of 20 more nuclear units. However, due to mounting public opposition following the nuclear accident in Tokaimaru in 1999, this policy target was lowered to 10 – 13 new units. According to the revised Outlook, more natural gas and coal-fired capacity, 50 percent each, will compensate for less nuclear generation. Implementing this measure is expected to result in 20 million tonnes more GHG emissions than in the previous report.

The revised Outlook also takes the view that industry will use more coal, which is cheaper than other energy sources, to improve cost competitiveness. Therefore, the revised Outlook emphasises the importance of natural gas utilisation and enhancement of new and renewable energy sources to curb GHG emissions.

RATIFICATION OF THE KYOTO PROTOCOL

Japan ratified the Kyoto Protocol on 4 June 2002. In order to achieve the emissions target, the climate change bill calls for the establishment of a detailed timeline, which will be reviewed in 2003 and in 2007 to ensure Japan meets the deadline. The Japanese government is required to harmonise existing laws related to energy use, including laws on energy conservation and the electric utilities industry to achieve the Kyoto target.

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KOREA

INTRODUCTION

Korea is located in East Asia on the southern half of the Korean peninsula. It has an area of about 99,000 square kilometres and a population of around 47 million (2000). Approximately 25 percent of the population lives in Korea's largest city, the capital, Seoul.

For the last few decades, Korea has been one of Asia's fastest growing and most dynamic economies. In 2000, real GDP per capita was US$16,594, more than three times higher than its 1980 level. Its major industries include electronics, automobiles and chemicals. Korea was severely affected by the Asian financial crisis in 1997. From 1990 to 1997, average GDP growth was 7.0 percent per year, but in 1998 real GDP fell by 6.7 percent. Recovery came quickly, and in 1999 real GDP was US$ 721 billion (1995 US$ at PPP), an increase of 11.3 percent over the previous year. A lower but still solid real GDP growth of 8.8 percent was achieved in 2000.

Korea has very few indigenous energy resources. It is completely without oil resources, coal reserves in 1999 were 646 Mt (anthracite), there is small amount of hydro potential and recently a small gas field was discovered offshore. To sustain its high level of economic growth, Korea imports large quantities of energy products. In 2000, Korea was the fourth largest importer of crude oil, the sixth largest consumer of oil, and the second largest importer of liquefied natural gas in the world.

Table 17 Key data and economic profile (2000)

Key data		Energy reserves	
Area (sq. km)	99,408	Oil (Proven)	0
Population (million)	47.28	Gas (Recoverable)	5.66 BCM*
GDP Billion US$ (1995 US$ at PPP)	784.48	Coal (Recoverable)	646 Mt**
GDP per capita (1995 US$ at PPP)	16,594		

Source: Energy Data and Modelling Center, IEEJ.

*Heat content is 10,200 kcal/m^3.

**Korea National Statistical Office, http://www.nso.go.kr

ENERGY DEMAND AND SUPPLY

PRIMARY ENERGY SUPPLY

Korea's total primary energy supply in 2000 was 188 Mtoe. Oil dominated primary supply comprising 53 percent of the total, followed by coal at 21 percent, nuclear at 15 percent, and gas at 9 percent, with hydro and other fuels making up the remaining 1 percent. Korea imported around 87 percent of its total energy needs in 2000, including all of its oil and gas requirements and 95 percent of its coal supply.

The Asian financial crisis had a notable impact on energy consumption in Korea. Primary energy supply increased by over 10 percent per year in the early 1990s and just below 10 percent in 1997. Consumption dropped by 7.6 percent in 1998 due to the financial crisis and the following economic downturn. But it picked up again, growing 10.2 percent in 1999 and 7.4 percent in 2000.

Korea has been importing liquefied natural gas (LNG) since 1986. Imports are managed by the state-owned monopoly LNG importer, Korea Gas Corporation (KOGAS). Korea buys the bulk of its LNG from Indonesia and Malaysia. In Korea, a small quantity of natural gas was recently discovered in the Dolphin 6-1 mining area offshore Ulsan in the southeast. The gas field, with 5.66 BCM of recoverable reserves, has been officially named Donghae-1 field and is expected to begin commercial operation in December 2003.

Until recently, the Korea Electric Power Corporation (KEPCO), a state-owned company, had a monopoly in electricity generation in Korea. The government has announced plans to break up and privatise the utility. In 2000, it began the process by splitting the generation assets of KEPCO into six separate subsidiaries. The privatisation plan, however, has been controversial. Unions fear job losses, and some politicians are concerned about foreign ownership.

At the end of 2000, KEPCO had a total power generation capacity of 47 GW. Electricity production in 2000 was 266 TWh. Thermal fuels accounted for 57 percent of production, followed by nuclear at 41 percent and hydro at 2 percent. There are currently 16 nuclear power plants in Korea. Two new power stations are under construction and have expected completion dates of 2004 and 2005.

Table 18 Energy supply & consumption (2000)

Total Primary Energy Supply	(ktoe)	Total Final Energy Consumption	(ktoe)	Power Generation	(GWh)
Indigenous Production	32,783	Industry Sector	73,922	Total	266,400
Net Imports & Other	154,822	Transport Sector	29,406	Thermal	151,826
TPES	187,605	Other Sectors	39,857	Hydro	5,610
Coal	40,290	TFEC	143,185	Nuclear	108,964
Oil	99,312	Coal	18,855	Others	0
Gas	16,995	Oil	88,947		
Others	31,009	Gas	11,536		
		Electricity & Others	23,849		

Source: Energy Data and Modelling Center, IEEJ (see http://www.ieej.or.jp/apec/database/selecttable.html)

FINAL ENERGY CONSUMPTION

Final energy consumption also grew at a rapid rate in the 1990s, averaging around 7 percent annually, and reached 143 Mtoe in 2000. Final consumption declined by 6 percent during the economic crisis in 1998, dropping 18 percent in the transport sector and 17 percent on average in the residential, commercial and public sectors. In the same year, however, consumption actually increased by 5 percent in the industrial sector, which is the largest final energy consumer. Final energy consumption then came back on track with growth of 9.6 percent in 1999 and 4.9 percent in 2000. By and large, demand growth in the industrial sector has weakened since the early 1990s, while the pace of demand growth in the residential, commercial and public sector has quickened.

In 2000, industry was responsible for 52 percent of consumption followed by 23 percent in the residential and commercial sectors and 21 percent in transportation. At the point of end-use, petroleum products were by far the most important energy source, accounting for 62 percent of demand. Electricity was responsible for 14 percent, coal for 13 percent and gas for 8 percent of end use. Due to strong policy measures, gas consumption has increased particularly in the residential and commercial sectors, from a small amount in 1990 to 8 percent of final energy consumption in 2000.

POLICY OVERVIEW

The Ministry of Energy and Resources (MOER) was created in January 1978 (Presidential Decree 8793, December 16, 1977) after the first oil shock. The current Energy and Resources Policy Office within the Ministry of Commerce, Industry and Energy (MOCIE) plays a role similar to its predecessor MOER. Its responsibilities include administration and policy-making for oil, gas, electricity, nuclear energy and coal, administration of short- to long-term energy demand and supply, oversight of energy prices, administration of the competitiveness of the energy industry and restructuring, and international cooperation on energy-related matters.

Sustaining high levels of economic growth despite inadequate indigenous energy resources has been and continues to be the key driver of Korea's energy policy platform. The Korean government projects that GDP will grow from 476 trillion won in 2000 to 1,170 trillion won in 2020 (at constant 1995 prices). In tandem, total energy demand is projected to increase 3.2 percent per annum between 2000 and 2010 and 1.7 percent per annum between 2010 and 2020.

In addition to finding energy supplies to satisfy rapid demand growth, Korea is very concerned about environmental degradation, the rapid integration of world energy markets, and increasing regional energy cooperation - especially in northeast Asia. To address these challenges, the following major energy policy goals have been developed:

- Secure more stable energy supplies;
- Establish a total energy demand management system;
- Enhance efficiency in energy industries and markets; and
- Construct an energy system linked to the continent through northeast Asian energy cooperation.

More emphasis is placed on securing a stable balance of energy supply and demand and structuring a more competitive energy industry in 2002.

OIL

Due to Korea's complete dependence on oil imports, the government has tried to secure and diversify current supplies in the short and long term. To smooth short-term supply disruptions and to meet its obligations to the International Energy Agency, of which Korea became an official member in March 2002, the Korean government plans to increase its strategic oil stocks from 29 days of net imports in 2000 (58.6 million barrels) to 60 days by 2006 with a 31.5-day stock (57.8 million barrels) in 2001.

In the longer term, to increase energy security, the Korea National Oil Corporation (KNOC) has been investing in exploration and development projects off the Korean peninsula as well as in international joint petroleum reserve projects. To date, KNOC has equity stakes in 19 overseas exploration and production projects in 12 different economies including Russia, Australia and Indonesia. To encourage private companies to invest in the development of overseas mineral resources, the Korean government has expanded its policy of supplying long-term low-interest loans through the Special Account of Energy and Resources. Korea is also an active partner with respect to Northeast Asian energy cooperation, an idea that combines the interests of both energy-consuming and energy-producing economies in the region.

NATURAL GAS AND COAL

To reduce the economy's dependence on imported oil, the Korean government has undertaken a number of measures to diversify fuel consumption. The introduction of natural gas-based city gas to the residential sector in the 1980s was promoted in order to expand the use of natural gas. Also, in order to secure a mass production system for anthracite, the only indigenous energy source, a supporting system for the coal mining industry was improved, and modernisation of mining equipment and integration of small-scale mines into large ones was promoted.

Ensuring a stable supply base through timely establishment of energy supply facilities is one of the important policy measures to achieve energy security goals. For example, LNG storage capacity increased to 2.6 MCM in 2002 from 2.28 MCM in 2001 when the third LNG terminal at Tongyeong on the southeast coast began operations in September 2002. A success story with respect to KNOC's domestic exploration efforts was the discovery of a commercially viable gas reserve (Donghae-1 field) on the continental shelf offshore Ulsan in the southeast. This field is expected to begin commercial production in December 2003.

ELECTRICITY

The total electricity generation capacity of Korea reached 48.5 GW in 2000 and 50.9 GW in 2001, which amounts to ten times the capacity level in the mid-1970s. According to the recently released First Base Plan for Long-Term Electricity Demand and Supply (2002-2015), which has replaced the old long-term electricity demand and supply plans that had been produced by KEPCO and MOCIE under the past regime, a total of 32.7 GW capacity will be added until 2015. Taking decommissioning into account, it translates into 77 GW of total generation capacity that year.

In order to rectify an energy supply and demand structure that was overly dependent on oil, construction of oil-fired power plants was strictly controlled and development of non-oil power sources such as nuclear, coal and gas was promoted. Korea has been building nuclear reactors since the 1970s, and nuclear power now accounts for more than 40 percent of electricity production. The capacity share of nuclear is envisaged to increase to 34.6 percent in 2015 from 27 percent in 2001, surpassing the traditionally largest share of coal-fired capacity. Gas-fired power plants were introduced in 1986 and now account for more electricity production than oil-fuelled plants, with capacity shares being around 25 percent and 9 percent, respectively. While the gas-fired share of generating capacity is expected stabilise at around the current level, the oil-fired share is expected to decline substantially to under 3 percent during the next 15 years.

ENERGY MARKET RESTRUCTURING

The Korean government believes that it is necessary to establish an electric power market where electricity is traded as a commodity. To this end, a programme of unbundling and privatisation for the Korea Electric Power Corporation (KEPCO) has been developed. Part of the plan has been implemented, including the establishment of the Korea Power Exchange and the Korea Power Commission in April 2001. Generating companies except for hydro and nuclear stations will be privatised step by step from 2002. Though a year behind schedule, separation of KEPCO's distribution arm will be launched in April 2004. Following restructuring of the electric power market, the Korean government will undertake the public interest functions of KEPCO by establishing the Electric Power Industry Foundation Fund. However, recent developments in the US regarding corporate accounting scandals and unsatisfactory performance of energy companies have had the effect reducing the pool of potential buyers of the generating companies.

Along with electricity market restructuring, the Korean government developed the Basic Plan for Natural Gas Industry Restructuring in November 1999. The plan outlines a scheme to separate and sell off the import and wholesale gas business in 2002. Nonetheless, the passage of three core pieces of legislation for the gas market restructuring – the Law of Korea Gas Corporation, the Law of Energy Commission and the Law of City Gas Business – is on hold in the National Congress of Korea. Major issues under controversy include the access to natural gas by consumers in remote areas, market power of gas suppliers after privatisation, default issues surrounding financing of LNG vessels, and transfer of gas sales and purchase agreements.

Other privatisation plans include the sell-off of 36 percent shareholding of each of the current public shareholders in the Korea District Heating Corporation, namely, MOCIE (46 percent), KEPCO (26 percent), KEMCO (14 percent) and the City of Seoul (13.8 percent), and floating of the remaining shares to the Korea Securities Exchange. This plan has been on hold and its abolition was in litigation in Korea's Supreme Court as of the summer of 2002. As the Higher Court has already rejected the application for abolition of the privatisation plan, it is likely that the plan will be implemented in the near future. Also, the deficit of the Daehan Oil Pipeline

Corporation is estimated to have been reduced during a one-year period to a level of one-third that of the previous year since its privatisation in January 2001.

ENERGY EFFICIENCY PROGRAMMES

Given Korea's vulnerability to supply disruptions, the government has promoted demand management, energy conservation and enhanced efficiency at the consumption stage. In the industrial sector, in order to minimise energy losses, to rationalise energy consumption, and to achieve an energy-saving industry structure, the Korean government enforced stringent administrative regulations in combination with financial and tax incentives. Adding to this, wider use of energy-saving equipment was encouraged and a national energy conservation campaign strengthened through public education and provision of information on energy conservation. District heating and cogeneration for industrial parks, factories and large buildings were also encouraged. As of the end of 2002, 8.4 percent of total households, or 1,077,515 households, were supplied by district heating, with an estimated energy saving amounting to 1,140 ktoe in 2001.

Supportive measures for energy saving were developed with regard to mobilising funds and constructing railroads and harbour facilities. More R&D on and introduction of advanced energy saving technology was also supported. Further, more efficient energy price structures were continuously developed and implemented to facilitate efficient use of energy and development of indigenous energy resources. Aided by these policies, the GDP elasticity of energy consumption has been rapidly cut in half, from 1.41 on average for the period from 1990 to 1997 to 1.21 in 1998, 0.85 in 1999 and 0.70 in 2000. To further promote energy conservation, the Korean government intends to develop voluntary agreements with large energy-consuming enterprises. The government hopes to increase the number of such agreements from 67 in 1999 to 567 by 2003.

Korea has recently launched several conservation programmes aimed at the residential and commercial sectors. At present there are three major energy efficiency programmes in operation: (1) the Energy Efficiency Standards and Labelling Programme which began in 1992 and targets some household appliances, lighting and automobiles; (2) the Certification of High Efficiency Energy-Using Appliance Programme implemented in December 1996; and (3) the Energy-Saving Office Equipment and Home Electronics Programme which began in April 1999. One key objective of these programmes is to give incentives to manufacturers to improve the energy efficiency of their products. Another key objective is to induce consumers to purchase more energy efficient products among those available in the marketplace. The Korean government has recently added dishwashers, electric water heater-coolers, and vehicles for 15 or fewer passengers to the list of the Labelling Programme. It will heighten efficiency standards for other energy-consuming devices within the next one or two years.

NOTABLE ENERGY DEVELOPMENTS

KOREA JOINS IEA

Korea became the 26th official member economy of the International Energy Agency (IEA) effective March 30, 2002, following the ratification by the National Congress of Korea of the Agreement on International Energy Program and its submission to the Belgian government. The Korean government announced its willingness to continue with its efforts to cooperate with other member economies toward the shared goals of the IEA through holding oil stockpiles, reduction of greenhouse gas emissions, and restructuring of the electricity industry. The government also stated that it would actively participate in the cooperative activities of the IEA, such as research, development and deployment of renewable energy technologies. Korea anticipates that its IEA membership will bring great changes to its energy sector, for example, developing a 90-day supply of oil stocks, coordinated utilisation of oil stocks, and implementation of IEA energy policies in the domestic market. However, it also believes that it will be able to enjoy substantial benefits such as a higher degree of energy security, more influence in world energy markets, and more efficient and flexible energy policies.

PRICE SUPPORT FOR NEW AND RENEWABLES TECHNOLOGY POWER GENERATION

A programme was launched effective 29 May 2002 to support the high cost of power that is generated using new and renewable energy (NRE) sources and sold in the restructured electricity market. As NRE power generation share was a mere 0.04 percent of total electricity generated in 2000, the Korean government is eager to see a notable growth of electricity generation using NRE, having set a target of 2 percent share in total primary energy supply by 2003. The price support is applied to five types of NRE sources, namely, photovoltaic, wind, small hydro, landfill gas, and waste incineration.

The programme is to compensate NRE power generators for the price-cost differentials (defined as base price or production cost less average market price of electricity in the previous year) for a five-year period from the start-up of commercial power plant operation. For example, 58.86 won/kWh will be compensated for electricity generated by a wind power plant in 2002, as the base price of wind power generated electricity has been set at 107.66 won/kWh and the average market price of electricity was 48.80 won/kWh in 2001. Following the same rule, photovoltaic generation will be supported at 667.60 won/kWh. The base prices may be adjusted, and those of other NRE sources will be determined taking into account changes of energy prices and technological development.

INCENTIVES FOR CNG BUSES

The Korean government announced its plan in September 2000 to promote replacement of diesel-powered buses with buses powered by compressed natural gas (CNG). As of March 2002, the number of CNG buses on the road surpassed 1,000, and it is expected to reach 3,000 by the end of 2000. However, these numbers are smaller than in the original plan, according to which there would have been 5,000 CNG buses by the end of 2000.

The slow penetration of CNG buses has been attributed to the difficulty in installing filling stations, insufficient price competitiveness of natural gas compared with diesel oil, and the relatively weak financial position of public transportation bus operating companies to replace the existing fleet. Relevant government bodies, mainly the Ministry of Environment and MOCIE, along with the business community, are searching for ways to achieve faster penetration of CNG buses, including wider use of mobile filling stations and a phased-in price increase for diesel. It is also envisaged that more CNG will be utilised for other types of vehicles such as municipal waste disposal trucks, low-bed buses and commercial trucks. A substantial amount of central and local government funding, totalling 13.4 billion won for 2002 and 19.8 billion won for 2003, has been set aside to support the price differential between CNG and diesel.

Other supportive measures include such tax incentives as exemption from value added tax and acquisition tax for the purchase of CNG buses. City gas companies responsible for construction and operation of CNG supply facilities will receive long-term low-interest loans. Amendment of the Clean Air Law is under way so that the substitution of CNG buses for diesel public transportation buses is obliged in the areas where CNG filling stations are available.

CREATION OF DEMONSTRATION SITE FOR NRE TECHNOLOGIES

MOCIE has launched a programme for evaluating practical uses of NRE technologies. The programme is expected to systemise and facilitate the whole process of technology development and deployment. It will help create a market for NRE products by enhancing their reliability through performance tests and research. The programme will be located in “green villages” supported by central and local governments. Green villages will be self-sufficient communities supplied with only new and renewable forms of energy. The City of Kwangju and City of Daegu were chosen to site green villages in 2001, and five green villages will be established by 2003.

Another newly announced plan, linked to housing supply policy, will provide houses powered by 3 kW capacity photovoltaic generation systems. According to the plan, 10,000 such houses will be built in green villages and “solar cities” by 2006, 20,000 by 2008, and 30,000 by 2010.

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MALAYSIA

INTRODUCTION

Malaysia is located in southeast Asia. Its 330,242 square kilometres of territory consist of Peninsular Malaysia and the Sabah and Sarawak states on the island of Borneo. The total population of Malaysia was 23.3 million in 2000 and grew an average of 2.7 percent per annum between 1980 and 2000. The population growth rate was expected to decline to 2.3 percent in 2002.

The Asian financial crisis in 1997 severely affected Malaysia's economy. GDP grew an average of 9.2 percent year from 1990 to 1997 but contracted by 7.4 percent in 1998. The economy began to stabilise in the second quarter of 1999 with the introduction of selective capital control and a host of other financial and fiscal measures. In 2000, Malaysia's GDP recorded growth of 8.3 percent, reaching US$195 billion or US$8,364 per capita (both in 1995 US$ at PPP).

Malaysia is well endowed with conventional energy resources such as oil, gas and coal, as well as renewables such as hydro, biomass and solar energy. As of December 2000, reserves included 542 million cubic metres (MCM) of oil, 2,336 billion cubic metres (BCM) of gas, 1,483 million tonnes (Mt) of coal, and more than 29,000 MW of hydropower capacity. Malaysia is a net energy exporter; 6 percent of its export earnings in 2000 came from mineral fuels and petroleum products.

Table 19 Key data and economic profile (2000)

Key data		**Energy reserves****	
Area (sq. km)	330,242*	Oil (Proven)	542 MCM
Population (million)	23.27	Gas (Proven)	2,336 BCM
GDP Billion US$ (1995 US$ at PPP)	194.62	Coal (Recoverable)	1,483 Mt
GDP per capita (1995 US$ at PPP)	8,364		

Source: Energy Data and Modelling Centre, IEEJ.

*Economic Planning Unit, Prime Minister's Department, 2001.

**National Energy Balance Malaysia, 2000.

ENERGY DEMAND AND SUPPLY

PRIMARY ENERGY SUPPLY

Total primary supply in 2000 was 57,868 ktoe. Gas accounted for 59 percent of total primary supply, while oil, coal and hydro accounted for 36 percent, 4 percent and 1 percent respectively. Most of the coal used in Malaysia was imported. Net energy exports of oil and natural gas made up 31 percent of total indigenous energy production.

Malaysia produced 30.8 million tonnes of crude oil in 2000. Almost 87 percent of production was exported to markets in Japan, Thailand, Korea, and Singapore. Most of Malaysia's oil fields are located offshore near Peninsular Malaysia. The Tapis field is the source of more than half of Malaysian production. To combat declining domestic reserves, Petronas, the state oil and gas company, is investing in exploration and production projects outside of Malaysia.

Gas production in Malaysia reached about 44.7 Mtoe in 2000, an increase of almost 150 percent from 1990. 37 percent of this gas was exported, usually in the form of liquefied natural gas (LNG), to Japan, Korea and Chinese Taipei. Gas is used domestically for electricity generation and as a feedstock in the petrochemicals industry.

In 2000, total electricity generation was 69,211 GWh. Thermal generation, mostly from natural gas, accounted for 90 percent of production and hydropower for the remaining 10 percent.

Table 20 Energy supply & consumption (2000)

Total Primary Energy Supply	(ktoe)	Total Final Energy Consumption	(ktoe)	Power Generation	(GWh)
Indigenous Production	84,112	Industry Sector	11,401	Total	69,211
Net Imports & Other	-26,244	Transport Sector	12,070	Thermal	62,249
TPES	57,868	Other Sectors	6,226	Hydro	6,962
Coal	2,308	TFEC	29,697	Nuclear	0
Oil	20,956	Coal	991	Others	0
Gas	34,005	Oil	19,581		
Others	599	Gas	3,862		
		Electricity & Others	5,263		

Source: Energy Data and Modelling Center, IEEJ (see http://www.ieej.or.jp/apec/database/selecttable.html)

FINAL ENERGY CONSUMPTION

In 2000, total final energy consumption in Malaysia was about 30 Mtoe. The transport sector consumed 41 percent of this total, followed by the industrial sector at 38 percent and other sectors (agriculture, residential/commercial and non-energy) at 21 percent. By fuel source, petroleum products contributed the largest share with 66 percent of consumption followed by electricity (18 percent), gas (13 percent) and coal and coke (3 percent).

POLICY OVERVIEW

The Prime Minister's Department, the Ministry of Energy, Communications and Multimedia and the Department of Electricity and Gas Supply are responsible for formulating Malaysia's Energy Policy and for regulating the quality of energy service. The Ministry of International Trade and Industry (MITI) and the Ministry of Domestic Trade and Consumers Affairs (MDTCA), through the Petroleum Regulations of 1974 (amended in 1975 and 1981), are vested with powers to regulate downstream petroleum activities. MITI, through the Malaysia Industrial Development Authority (MIDA), issues licences for the processing and refining of petroleum and the manufacture of petrochemical products. MDTCA issues licences for the marketing and distribution of petroleum products.

Malaysia's energy policies took shape during the early 1970s after the 1973 world oil crisis. The cornerstones of Malaysian petroleum policy were fleshed out in the Petroleum Development Act (PDA) of 1974 and the National Petroleum Policy of 1975. This legislation aimed to regulate the oil and gas industry to achieve economic development needs. It outlined the following policy goals:

- Making sure adequate energy supplies at reasonable prices are available to support national economic development objectives;
- Promoting greater Malaysian ownership and providing a favourable investment climate, including creating opportunities for downstream industries; and
- Developing oil and gas resources at a socially and economically optimal pace, while conserving these non-renewable assets and protecting the environment.

The PDA established Petronas as a state-owned enterprise with exclusive ownership, exploration and production rights. It comes under the direct purview of the Prime Minister and is responsible for planning, investment and regulation of all up-stream activities. The PDA also introduced a system of production sharing contracts (PSCs) to replace the previous system of concessions. In these ways, the oil and gas sector was streamlined to ensure greater Malaysian participation in the ownership, management and control of oil and gas resources and activities.

NATIONAL ENERGY POLICY OBJECTIVES

In 1979, Malaysia's energy policy principles were broadly defined in terms of three policy objectives. These policy objectives are instrumental in guiding the formulation of five-year development plans. They are:

- *The Supply Objective:* To ensure the provision of adequate, secure and cost-effective energy supplies by developing indigenous energy resources, both non-renewable and renewable, using least-cost options, and diversifying supply sources both within and outside the economy;
- *The Utilisation Objective:* To promote the efficient utilisation of energy and the elimination of wasteful and non-productive patterns of energy consumption; and
- *The Environment Objective:* To minimise the negative impacts of energy production, transportation, conversion, utilisation and consumption on the environment.

THE SUPPLY OBJECTIVE

In pursuing the supply objective, Malaysia has implemented polices to extend the life of non-renewable energy resources such as oil and gas and to reduce dependence on oil by encouraging the use of other energy forms.

The National Depletion Policy of 1980 was developed to preserve declining oil reserves. The policy, aimed at major oil fields of over 400 million barrels of oil initially in place (OIIP), restricted production to 1.75 percent of OIIP. However, the initial restriction proved too conservative, and in 1985, the ceiling was raised to 3 percent of OIIP. Due to this policy, total production of crude oil is limited to about 650,000 barrels per day. At the current production rate, proven oil reserves are expected to last another 10 years. The National Depletion Policy was later extended from crude oil to include natural gas reserves. An upper limit of 56.6 MCM per day (2,000 million standard cubic feet per day) has been imposed in Peninsular Malaysia. At the current rate of production, known natural gas reserves are expected to last for about 60 years.

In 1981, to complement the National Depletion Policy and ensure the reliability of supply, the government adopted the Four-Fuel Strategy. This strategy was designed to reduce the economy's dependence on oil, and its goal is to achieve a balanced energy supply mix of oil, gas, hydropower and coal. As much as possible, development of domestic resources is encouraged to enhance security of supply. Under this initiative, oil share has fallen significantly. Consumers, particularly the power sector, have substituted away from oil towards natural gas which is available domestically and is "environmentally-friendly" compared to other fossil fuels. In June 1999, the Prime Minister announced that the Four-Fuel Strategy would be revised to become a Five-Fuel Strategy. Recognising the potential for renewable energy resources and emphasising its commitment to promote renewables and preserve the environment, Malaysia adopted renewables as its "fifth fuel."

THE UTILISATION OBJECTIVE

There have been limited initiatives to pursue the utilisation objective. Demand side management initiatives by the utilities, particularly through tariff incentives, have encouraged more efficient use of energy. Most energy efficiency initiatives are aimed at large energy consumers such as industry. The Malaysian Industrial Energy Efficiency Improvement Programme launched in July 1999 is a collaborative effort between the government of Malaysia and the UNDP/Global Environmental Facility (GEF). This 4-year project aims to remove energy efficiency barriers, encourage rational use and improve energy efficiency in Malaysian industries. Other industrial energy efficiency initiatives currently being planned include an energy auditing programme, an energy service companies support programme and a technology demonstration programme.

In 1998 the Malaysia Energy Centre (MEC) was established as an independent non-profit entity to formulate, coordinate and manage energy-related research and development programmes and promote the development of indigenous technologies. Officially launched by the Prime Minister during the World Renewable Energy Congress in June 1999, in Kuala Lumpur, one important role of MEC is to promote renewable energy and energy efficiency programmes in Malaysia and to formulate innovative financing mechanisms to make these projects commercially viable.

THE ENVIRONMENT OBJECTIVE

In support of the environment objective, all major energy development projects are subjected to a mandatory environmental impact assessment (EIA) requirement. Recently, Malaysia was evaluated to be the third cleanest economy in Asia behind Japan and Singapore.

NOTABLE ENERGY DEVELOPMENTS

RESTRUCTURING OF THE ELECTRICITY SUPPLY INDUSTRY

The government of Malaysia has decided that the economy's power supply industry will not be fully privatised. Tenaga Nasional Berhad (TNB) will continue to generate and distribute power. Nevertheless, restructuring of the power industry will be continued, with a market mechanism gradually introduced to attract investments and ensure an adequate and reliable supply of electricity. This will involve establishment of an appropriate infrastructure and regulatory framework. The government has authority to restructure the power industry through amendments to the Power Supply Act of 1990. An independent Energy Commission became the economy's energy sector regulator when the Energy Commission Act of 2000 (Act 610) came into effect on May 1 2001. In addition to improving the effectiveness of economic and safety regulation in the gas and electricity industries, the Commission will promote technologies for renewable energy and energy efficiency.

There is an ongoing effort to restructure the electricity supply industry to promote efficient use of financial and technical resources in the industry and ultimately to achieve competitive electricity prices for all customers. As part of this effort, Malaysia will implement an open bidding system for power plant construction projects after 2005 to replace the current practice of awarding projects directly to companies. The implementation of the open bidding system is aimed at promoting greater transparency and encouraging lower-cost power production. No new power plant is anticipated to be constructed in the next few years as the capacity from the existing ones and those under construction should be sufficient for now.

RENEWABLE ENERGY (RE)

To enhance excessive dependency on natural gas, which today accounts for 80 percent of the fuel used for power generation, the government has set an objective to make renewable energy (RE) account for 5 percent of power supply or some 600 MW of generating capacity by 2005. Ways are being studied to efficiently utilise the abundant RE resources available locally such as the biomass technology for transformation of oil palm wastes to fuel. These steps are in line with the government's decision to intensify development of RE as the fifth fuel resources under the economy's Fuel Diversification Policy as stipulated in the Eighth Malaysia Plan, in addition to gas, oil, hydropower and coal. A special committee has been established in the Ministry of Energy, Communications and Multimedia to coordinate implementation of the RE intensification strategy.

SMALL RENEWABLE ENERGY POWER PROGRAMME

To further support the efforts to diversify energy sources, the Small Renewable Energy Power (SREP) Programme was launched in May 2001 to gain first hand experience of feeding renewable energy-based electricity into the national grid. This programme was initiated with the objective of promoting the wider use of the huge amount of RE resources available in Malaysia particularly biomass (oil palm and wood wastes). A secretariat for the programme has been set up at the Ministry's Department of Electricity and Gas Supply to facilitate industry participation.

SREP projects are defined as power generating projects that are capable of converting RE resources onto electricity. The utilisation of all types RE including biomass, biogas, municipal waste, solar, mini hydro and wind is allowed under this programme. The size of a power plant can be greater than 10 MW, but the maximum capacity allowed for power export to the distribution grid must not exceed 10 MW. Small power generation plants which utilise RE can apply to sell to the utility through a distribution grid. Project developers are required to negotiate directly with the relevant utility on all aspects of the Renewable Electricity Purchase Agreement, including the selling price on a willing-seller, willing buyer and take-and-pay basis.

In early October, TNB signed agreements to purchase RE-based electricity from two small-scale, independent RE power developers. Bumibiopower Sdn Bhd will deliver biomass-fuelled electricity at 16.7 sen per kWh for a period of 21 years from a plant at Pantai Remis, Perak which will be operational in two years. Jana Landfill Sdn Bhd will receive 16.5 sen per kWh for electricity generated using methane extracted from the sanitary landfill at Puchong, Selangor.

EDUCATION AND TRAINING IN RENEWABLE ENERGY AND ENERGY EFFICIENCY

Malaysia has established the Centre for Education and Training in Renewable Energy and Energy Efficiency (CETREE) aimed at increasing public awareness of the positive attributes of RE and energy efficiency measures. Under the Eighth Malaysia Plan, CETREE had been recognised as a centre to assist the school and university education sectors in upgrading knowledge and awareness of renewable energy and energy efficiency.

POWER PLANT SECTOR DEVELOPMENT

In anticipation of the increase in demand for power resulting in the need for additional capacity from 2008 onwards, the government revived the Bakun Hydroelectric Project in early 2002, albeit at a smaller scale than originally planned. Sarawak Hidro Sdn Bhd, a company under the Ministry of Finance Incorporated, has been designated as the project implementing agency. Thirteen consortiums have been short listed for the pre-qualified tender for the civil works of the RM9 billion dam project. When completed, Bakun will have a total capacity of 2,400MW for use in Sabah, Sarawak, Brunei Darussalam and possibly also Kalimantan.

As a first step in the Bakun hydro project, Sarawak Hidro has awarded a contract for construction of a coffer dam to Global Upline Sdn Bhd. The coffer dam will create a dry area across the river so that the main dam can be built. The project's civil works, estimated to cost between RM2 billion and RM3 billion, will also include the main dam, spillway, power tunnel, power tower and ancillary roads. Construction of the Bakun dam is expected to commence in the third quarter of 2003, following announcement of a winning bid by the Ministry of Finance.

Agreements were signed by TNB in July 2001 for construction of coal-fired power plants by two independent power producers, Jimah Power Sdn Bhd and SKS Ventures Sdn Bhd. These coal-fired power plants are in line with the economy's efforts to reduce reliance on natural gas. The development of the two power plants will be staggered, with some units coming on stream in 2006 and others in 2007. Jimah's power plants will have a final capacity of 2x700 MW to be built in Mukim Jimah, Negeri Sembilan. SKS Ventures' power plants will have a final capacity of 3x700 MW to be built in Pulau Bunting, Kedah. TNB has paved the way for detailed negotiations on the power purchasing agreement (PPA) with the companies. TNB has also signed a PPA with Panglima Power Sdn Bhd for the installation of a plant in Teluk Gong, Malacca.

EXPLORATION AND PRODUCTION OF CRUDE OIL

At January 1, 2002, Malaysia's oil reserves were 4.2 billion barrels (including condensates). According to BP Statistical Review of World Energy 2002, Malaysia's crude oil reserves at December 31, 2001 ranked as the 27th largest in the world. At the current production level of approximately 695,000 barrels per day (including condensates), Malaysia's current oil reserves (including condensates) would last for approximately 17 years.

At 1 January 2002, Malaysia's gas reserves were 87.5 trillion cubic feet. These reserves are expected to last for 34 years based on planned production levels. The production level for fiscal year 2002 was 2 trillion cubic feet. According to BP Statistical review of World Energy 2002, Malaysia's natural gas reserves at December 31, 2001 ranked as the 14th largest in the world.

Petronas explores for, develops and produces oil and gas in Malaysia through production sharing contracts with international oil and gas companies and its wholly-owned subsidiary, Petronas Carigali. As of 30 September 2002, there were 43 production-sharing contracts in effect, with 10 operators from 10 different countries. Of the 495,321 square km of land and seabed available for oil and gas exploration in Malaysia, 192,806 square km are covered by PSCs. As of January 2002, exploration of the continental shelf had resulted in discovery of 134 oil fields and 173 gas fields. Malaysia's deeper offshore areas, with water depths of 200 meters or more, are open to oil and gas exploration, and to-date, Petronas has awarded 10 deepwater PSCs. Efforts are also being undertaken to develop small fields and enhance production of mature fields in Malaysia.

At 30 September 2002, Petronas had 46 producing oil fields in Malaysia. These oil fields produce seven blends of crude: Tapis, Labuan, Miri Light, Bintulu, Bunga Kekwa, MASA and Dulang. All of these blends are of high quality and generally command a premium price over benchmark Brent crudes on the world market. In fiscal year 2002, Malaysia's crude oil and condensates production was 246 million barrels, a slight decrease from the production level of 249 million barrels in fiscal year 2001. Target production levels are expected to be approximately 255 million barrels per year through 2007.

Petronas is seeking to augment its reserves and ensure the adequacy of Malaysia's petroleum supplies through exploration, development and production activities outside Malaysia. The company participates in 39 production sharing contracts, 3 service contracts and 7 concession agreements in three regions: Africa, Middle East and Asia. Its E&P globalisation programme, which started in 1990, has extended to 23 countries, including new upstream interests in Yemen, Togo, Equatorial Guinea and Mozambique. As a result of its increasing overseas activities, Petronas has accumulated international oil and gas reserves of approximately 3.7 billion barrels of oil equivalent as of 1 January 2002. Some of the notable developments in the company's international business during 2002 were as follows:

- In the Republic of Chad, Petronas has a 35 percent interest in a consortium with ExxonMobil and Chevron Texaco for an investment in upstream and downstream activities. Upstream activity involves exploration in Doba Basin. Downstream activity involves the construction of 1,070 kilometres oil pipeline from Kome, Chad to Port Kribi, Cameroon. Production is expected to commence in July 2003.
- In Sudan, production commenced in August 2002 and has a capacity of 40,000 b/d. In September 2002, Petronas entered into a sale and purchase agreement to acquire a 40 percent interest in Blocks 3 and 7 from Ansan Wikfs Investment Ltd.
- In March 2002, Petronas acquired 31.7 percent participation interest in a production sharing agreement with Canadian Nexen Yemen Ltd and Kerr-McGee Hazar Ltd for Block 50. In April 2002, Petronas Carigali Overseas entered a production sharing agreement for Block 52 in Sarr Area of which it holds a 65 percent interest in the block.
- Petronas has entered into two farm-in agreements in Indonesia for Karapan Block with 50 percent interest and Jabung Block with 30 percent interest, in March and June 2002 respectively. Jabung Block is currently producing at 23,000 b/d.
- In January 2002, Petronas, Petro Vietnam Investment & Development Company and Pertamina formed Con Son Joint Operating Company to explore Blocks 10 and 11.1 n the southern continental shelf of Viet Nam. Petronas has a 30 percent interest in the venture. Drilling activities are expected to commence in 2003.

GAS DEVELOPMENT

Development and utilisation of gas continues to be the main thrust of Petronas' activities to exploit the economy's substantial gas reserves through value-adding projects. Completion of Gas Processing Plant 6 has expanded the capacity of the Peninsular Gas Utilisation (PGU) system by one third, to 2,000 million standard cubic feet per day.

To ensure the sufficiency of Malaysia's natural gas supply and prolong the economic life of domestic gas reserves, Petronas has signed an agreement with Pertamina to purchase gas from Indonesia's West Natuna Sea area amounting to 1.5 TCF over a 20-year period. The first gas delivery was received via a pipeline to Petronas' Duyong Gas Field facilities located offshore Terengganu on 8 August 2002. The 100-km pipeline is the latest component of the growing interconnection of cross-border gas infrastructure in ASEAN and charts another important step towards the realisation of the Trans-ASEAN Gas Pipeline (TAGP). Interconnection with existing and future infrastructure in the gas-prolific areas of ASEAN will enhance security of gas supply to meet the region's increasing energy requirements.

Petronas and Pertamina signed a Memorandum of Understanding on 8 August 2002 to facilitate a Gas Sales Agreement (GSA) from South Sumatra to Malaysia. The GSA, expected to be concluded by the end of 2002, will result in the supply of 300 million standard cubic feet of gas per day to Malaysia for 20 years. Delivery of the gas is scheduled to commence in early 2005. Work is also progressing to link the PGU system to the Trans-Thailand Malaysia Pipeline project. The project will add another building block to the emerging Trans-ASEAN Gas grid.

Petronas' international gas production comes from Myanmar (Yetagun field Blocks M12, M13 and M14) and Iran (South Pars Phases 2 and 3). Currently, the interests of the parties in the Yetagun field and the gas pipeline consist of Petronas International Capital Ltd (PICL, 30 percent), Premier Petroleum Myanmar (27 percent), Nippon Oil (14 percent), PTTEPI (14 percent) and MOGE (15 percent). In September 2002, PICL entered into an agreement to relinquish its 25 percent share of Premier's stock and pay Premier US$359 million in cash and debt in return for Premier's stake in Yetagun and Premier's 15 percent interest in Natuna Sea Block A in Indonesia.

NATURAL GAS VEHICLE (NGV) PROGRAMME

Petronas introduced a natural gas vehicle (NGV) programme in 1986 as part of its efforts to add value to the economy's abundant natural resources. Today, the company has close to 4,000 NGVs, including 1,000 units of *Enviro 2000*, in and around Kuala Lumpur. These are served by 21 NGV refuelling stations which receive gas through pipeline or trailer systems. Exhaust emissions from these NGVs is well below EURO II limits on carbon monoxide, hydrocarbon and nitrogen oxide. The NGVs can travel up to 480 km on a full tank of natural gas, so its range is equivalent to that of a petrol powered vehicle. More importantly, these NGVs significantly lower fuel expense.

Petronas' subsidiary, Petronas NGV Sdn. Bhd., signed a three-year Memorandum of Understanding (MoU) with the Petroleum Authority of Thailand (PTT) on 1 June 2001 to introduce the *Enviro 2000* natural gas-powered vehicle in Thailand. The MoU is part of a long-term approach to be undertaken by both parties to promote NGV businesses in Thailand. Under the MoU, Petronas NGV will embark upon a six-month field demonstration on the roads in Bangkok involving five *Enviro 2000* NGVs like those that have served as taxis in Kuala Lumpur since 1998. In Thailand, the vehicles are expected to be utilised for public transportation as well as by officials. The field demonstration will contribute to Petronas' plans to promote and create market awareness of NGVs and *Enviro 2000* outside Malaysia, in line with its continuous efforts to increase the use of gas as a cleaner, cheaper and environment-friendly alternative fuel.

The terms of the MoU also call for both parties to undertake a joint feasibility study on the development of other related NGV businesses in Thailand. These would include areas like NGV refuelling station construction and operation, promotion and marketing of NGV and production of bi-fuel and monofuel NGV vehicles in Thailand. Upon request, Petronas NGV will provide technical assistance and expertise to PTT in relation to the development of regulations and safety standards for NGV vehicles, refuelling stations and other related matters.

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MEXICO

INTRODUCTION

Mexico is located in North America, bordering the US to the north and Belize and Guatemala to the south. Mexico is one of the most populous economies in Latin America, with a total population of about 97 million people. Due to industrialisation and urbanisation in recent years, around three-quarters of the population lives in urban areas. Mexico City has the largest urban concentration of people in the world, with some 18 million people within the city limits.

In the last twenty years, the economy has suffered three economic downturns: in 1982, 1988 and 1995. As a result, and due to the declining value of the peso, the real average GDP growth rate at purchasing power parity was just 1.7 percent per annum from 1980 to 1995. However, with continuing economic and political reform, the Mexican economy has recovered rapidly in the last few years. The average real growth rate was 5.5 percent per annum between 1995 and 2000, and the economy grew 6.9 percent between 1999 and 2000. An economic slowdown in the United States, Mexico's most important trade partner, produced an economic contraction of 0.3 percent in 2001. Still, stable political conditions within and continuing economic growth in the US are counted upon for the economy to regain average growth rates close to 5 percent within a few years.

Mexico is a major non-OPEC oil producer. Together with other independent producers and OPEC, it has been a main contributor to the stabilisation of crude oil market prices. The oil industry plays a crucial role in the economy, accounting for about one third of government revenues. Mexico also has abundant natural gas resources, with several projects under development. In January 2001, proven oil reserves were the ninth largest in the world, totalling 4,283 MCM (including condensates and plant liquids), gas reserves were 826 BCM and coal resources were 1,211 Mt.

Table 21 Key data and economic profile (2000)

Key data		Energy reserves	
Area (sq. km)	1,964,375*	Oil (Proven)	4,283 MCM**
Population (million)	97.97	Gas	826 BCM**
GDP Billion US$ (1995 US$ at PPP)	864.23	Coal (Recoverable)	1,211 Mt
GDP per capita (1995 US$ at PPP)	8,822		

Source: Energy Data and Modelling Center, IEEJ.

*INEGI (2002), *Estadísticas Sociodemográficas.*

**Secretaría de Energía, *Programa Sectorial de Energía 2001-2006.*

ENERGY DEMAND AND SUPPLY

PRIMARY ENERGY SUPPLY

Total primary energy supply in Mexico was 152 Mtoe in 2000. Oil and gas dominate primary energy supply with a combined share of 83 percent, with oil contributing 56 percent and gas 27 percent. Coal provides 5 percent of primary energy, geothermal energy 3 percent, hydropower and nuclear power 2 percent each, and other fuels 5 percent.

Mexico has the second largest proven oil reserves in the western hemisphere. In 2001, Mexican oil production increased by 4 percent to 156 Mtoe. Approximately 55 percent of production was exported, with the US being the largest customer. The state oil company, PEMEX, is one of the ten largest oil companies in the world, in terms of both assets and revenue. By law, PEMEX is the sole producer of oil in Mexico from upstream exploration to final distribution. In the gas industry, storage, transportation, distribution and sales segments of the market have been opened to the private sector. Foreign investors are limited to services and specified contracts.

Offshore oil sites in the Campeche Sound of the Gulf of Mexico contribute around 77 percent to total Mexican oil production. PEMEX is concentrating on the Cantarell heavy oil project, which has consumed roughly half of its 3-year investment budget for exploration and production. In 2000, Mexico and United States settled the maritime boundary dispute over the Western Gap area in the centre of the Gulf of Mexico. It was agreed that 62 percent of the region belonged to Mexico and 38 percent to the United States. Due to technological advances in deep water (3,000 metre) drilling in recent years, oil exploration and development in this area has become feasible.

A 700-mile pipeline under construction between offshore sites in Veracruz and refinery installations, will allow PEMEX to upgrade its oil transport infrastructure. PEMEX also controls the downstream oil sector. It has six major refineries which are currently being upgraded to increase the volume and improve the quality of gasoline and distillate production.

Indigenous production of natural gas in Mexico was 4.5 billion cubic feet per day (Bcf/d) in 2001, about 4 percent less than the year before. However, gas production in Mexico is expected to reach 7.5 Bcf/d by 2010. Mexico exports a small portion of its gas production to the United States, amounting to just 25 million cubic feet per day (Mcf/d) in 2001. But gas exports are far outweighed by gas imports, with net imports from the US climbing by 26 percent to 292 Mcf/d in 2001. Domestic gas demand is growing more rapidly than production, and imports are therefore expected to satisfy as much as one-fifth of domestic gas demand by 2010.

With increasing market demand and environmental considerations, natural gas consumption is expected to grow substantially in coming decades, particularly in the power sector. In the decade through 2010, total gas consumption is expected to more than double while power sector gas demand is expected to almost quadruple. In anticipation of this growth, new projects are underway in gas field development and gas processing, transport and distribution. There are plans to increase domestic gas supply by focusing investments on gas exploration activities and transportation infrastructure. Since gas is mainly produced in the south of Mexico while markets are located in northern and inland areas, enhanced pipeline infrastructure is vital to gas market development.

Mexico is considering at least one receiving terminal for LNG. The most viable site appears to be Altamira in the State of Tamaulipas on the Gulf coast. However, a couple of sites in Baja California and Jalisco on the Pacific Coast are also possibilities. Imports of natural gas liquids could come from Africa, South America, Russia or Asia.

Primary coal supply in 2000 was 7 Mtoe while indigenous bituminous coal production was 5.4 Mtoe. To supplement production, coal is imported from the United States, Canada, and Colombia. The power and steel sectors are the main coal consumers. Coal resources, which have a high ash content, are located in the north of Mexico. Minera Carbonífera Rio Escondido (MICARE), which used to be state-owned, is the biggest coal producer in Mexico and is now owned by Mission Energy of the US. Indigenous coal production is expected to decline in the future since imported coal is cheaper than domestic coal for power generation.

Electricity demand has grown rapidly over the past decade, with an average growth rate of 5.1 percent per year. Electricity consumption reached 168 TWh in 2000 and is expected to increase by an average of 5.7 percent per year over the next twenty years. The Mexican electric grid is well developed; 95 percent of the population has access to electricity.

Electricity generating capacity in 2000 was 40,650 MW, of which 63 percent was thermal and 24 percent was hydro. Fossil fuel thermal power plants contributed 66 percent of electricity produced in 2000, while hydropower contributed 16 percent, 5 percent came from a two-unit nuclear power plant, and 3 percent came from geothermal and other sources. Mexico also imported some electricity from the US to accommodate sharply increasing demand in the border area, and similarly exported a small amount to Belize in the south. For environmental reasons, Mexico plans to encourage combined cycle natural gas power plant construction in the future.

Mexico is thought to have large reserves of renewable energy resources. To date, attention has focused on developing hydro and geothermal resources. Hydropower, with 9,618 MW operating in 2000, accounts for 24 percent of installed electric generating capacity. Installation of a further 3,191 MW of hydropower is expected in the next ten years. In 2000 there were 855 MW of installed geothermal power generating capacity, making Mexico the second largest geothermal electricity producer in the world. Another 123 MW of geothermal capacity are planned for construction in the next ten years. Wind and biomass power generation are being evaluated for future power production potential. Solar energy is being promoted as a power source for isolated rural communities.

Table 22 Energy supply & consumption (2000)

Total Primary Energy Supply	(ktoe)	Total Final Energy Consumption	(ktoe)	Power Generation	(GWh)
Indigenous Production	228,968	Industry Sector	29,480	Total	191,426
Net Imports & Other	-77,180	Transport Sector	38,550	Thermal	144,220
TPES	151,789	Other Sectors	28,430	Hydro	33,076
Coal	7,008	TFEC	96,460	Nuclear	8,221
Oil	84,849	Coal	2,244	Others	5,909
Gas	41,651	Oil	60,728		
Others	18,279	Gas	11,987		
		Electricity & Others	21,501		

Source: Energy Data and Modelling Center, IEEJ (see http://www.ieej.or.jp/apec/database/selecttable.html)

FINAL ENERGY CONSUMPTION

As a result of the periodic economic downturns, energy consumption has fluctuated significantly over the last twenty years. However, the average growth rate in energy demand was 2 percent per annum over the period from 1980 to 2000. Total energy consumption in 2000 was 96.5 Mtoe. Transport accounted for 40 percent of consumption in 2000, industry for 31 percent, the residential and commercial sectors for 21 percent, agriculture for 3 percent, and non-energy uses for 5 percent.

ENERGY POLICY OVERVIEW

The energy sector has traditionally been controlled by state-owned monopolies, but liberalisation programmes have been carried out in recent years. The natural gas market is the most deregulated of Mexico's energy sectors. PEMEX maintains a monopoly in upstream exploration and production, but since the passage of the Natural Gas Law in 1995, private and foreign investors have been allowed to invest in downstream activities such as natural gas transportation, storage and distribution as well as gas imports and exports. To prevent vertical integration within the industry, companies are not permitted to operate in more than one segment of the market.

For environmental and economic reasons, the federal government's fuel policy promotes the use of natural gas technologies, especially combined-cycle plants, for electricity generation. This policy is two-pronged: most new capacity additions are expected to be gas-fired, and thermal plants should be converted from fuel oil to natural gas wherever it is economically feasible to do so.

In the electricity sector, private investors are allowed to participate in power generation as independent power producers, auto-producers and co-generators. The electricity transmission and distribution systems are still controlled by state-owned Comision Federal de Electricidad (CFE) and Luz y Fuerza del Centro (LFC). Mexico plans to continue with reforms that will allow private investment to help increase the electricity supply, improve the transmission and distribution systems and increase efficiency.

NOTABLE ENERGY DEVELOPMENTS

OIL AND GAS SECTOR DEVELOPMENTS

Mexico has actively worked with other non-OPEC oil producers and OPEC to reduce oil production and help stabilise oil prices. In January 2002, as on previous occasions, Mexico implemented a cut in production and exports for six months. On 26 June, OPEC decided to maintain its current agreed production and export levels through September 2002. So did Mexico even though non-OPEC economies Norway and Russia decided otherwise.

To promote dialogue between OPEC and Non-OPEC countries, Mexico hosted a meeting in Puerto Vallarta with the Energy Ministers of Venezuela and Saudi Arabia to analyse the international oil market. Participants endorsed continued dialogue among consumer and producer economies and agreed on the importance of stable markets to maintain investment that will ensure future oil supply.

Mexico's first dry, non-associated natural gas field was recently discovered off the coast of the state of Campeche. This field, together with two new developments off the coast of Veracruz, will add 50 BCM to present gas reserves. Still, gas production only increased by 3 percent from January to August 2002, requiring an increase of 144 percent in gas imports. This dramatically underlines the need for greater investment in gas resource development.

Investments in the oil refining industry slowed in the past to the point where Mexico became an oil product importer as of 1996. New efforts to assign resources to refining have allowed the share of oil products supplied domestically to increase from 87 percent in 2000 to 93 percent in 2001. But strong demand growth will still require importation of oil products for at least the next ten years.

OIL AND GAS SECTOR RESTRUCTURING

Even though PEMEX is the tenth largest oil company in the world in terms of revenue, it also has the distinction of having had negative profits in the last few years. PEMEX is the subject of a fiscal and tax system in which it surrenders 60.8 percent of its revenue to the Federal Government for the national budget. As much as 36 percent of the federal budget is made up of revenues from the state oil company. Another contributing factor to low profits at PEMEX is the heavy burden imposed by the largest personnel base (some 139,000 workers in 2000) among the world's major oil companies.

Mexico is striving to restructure its energy sector to increase the flow of fresh monetary resources to the under funded oil and power sectors. In addition to a change in the tax structure that would allow PEMEX to retain a larger portion of revenue for investment in oil-production and refining capacity, the government has plans to liberalise parts of the energy industry in hopes of attracting both domestic and foreign private investment. The government is also exploring the possibility of using innovative concessions and permits schemes to encourage the participation of local and international investors in energy activities now reserved for the state, such as oil refining, petrochemicals and even exploration and production of natural gas.

PEMEX is promoting 20-year "multiservice" contracts among private investors for surveillance, drilling and production of natural gas in the Burgos region of northern Mexico. In these contracts, of a type previously used in Iran and Venezuela, PEMEX pays the contractors a set fee for the services provided but retains ownership of the natural gas produced. This circumvents the constitutional prohibition on exploitation of national resources by entities other than the state.

In 2002, a record US$10 billion was expected be spent on oil and gas exploration and production in Mexico, allowing the highest level of oil production the economy has ever experienced. The 53 new gas exploration wells and 406 gas development wells that were finished in 2001 are the largest numbers of wells completed in 15 years and 33 years, respectively.

POWER SECTOR DEVELOPMENTS AND RESTRUCTURING

On the power industry front, the second restructuring bill in four years was submitted by the President to Congress for approval. Like PEMEX in the oil and gas industry, for many years the state power companies Comision Federal de Electricidad (CFE) and Luz y Fuerza del Centro (LFC) enjoyed monopolies in the electric power sector. Legislative reforms in 1992 made it possible for independent power producers (IPPs), auto-producers and co-generators to sell power, but CFE still owns most of Mexico's installed electric generating capacity and generates over 90 percent of the electricity consumed in Mexico. Electricity demand is expected to grow very quickly over the next two decades while infrastructure investment by CFE is expected to decline.

In 2002, total investments in power generation infrastructure in CFE and LFC will be US$4.8 billion, a 28.5 percent increase over the previous year. The budget for investment in transmission will triple in the same year, reaching US$1.6 billion. The government maintains that in the future it will be harder and harder to appropriate the necessary funds to expand the power infrastructure at the rates required by rapidly increasing demand. After a failed attempt by the previous government at passing a reform bill in Congress, the bill proposed by the present government has a better chance at passing as it incorporates less aggressive liberalisation measures that are more likely to be accepted by all the different political parties involved. An important political factor in the reform debate is the energy sector's strong labour unions, which see reform as a potential threat to their livelihood.

The present reform proposal would allow private generators to compete with government-owned utilities in wholesale markets. The output of all generators would be dispatched on a non-discriminatory basis by a regulated independent system operator. The reform proposal would also allow state power companies to increase investment in power generating capacity and transmission facilities by providing them with greater operational and financial independence, reforming their fiscal and tax structure, and changing the system of investment subsidies so that they are funded through the federal budget rather than from the companies' revenue.

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NEW ZEALAND

INTRODUCTION

New Zealand is a small island nation in the southern Pacific with a population of approximately 4 million in 2000. GDP has grown around 2.7 percent per annum in the decade to 2000 reaching about US$ 72.6 billion in 2000.

New Zealand had modest energy resources including 17.5 MCM of oil, 62 BCM of natural gas, 8,600 Mt of coal and hydro and geothermal resources that currently meet around 70 percent of electricity demand. New Zealand is self-sufficient in all energy forms apart from oil. Energy contributes about 3 percent to New Zealand's gross domestic product (GDP), and directly employs about 9,000 people, or around 0.5 percent of the workforce.

Table 23 Key data and economic profile (2000)

Key data		Energy reserves*	
Area (sq. km)	268,680*	Oil	17.5 MCM
Population (million)	3.83	Gas	62 BCM
GDP Billion US$ (1995 US$ at PPP)	72.56	Coal (Recoverable)	8,600 Mt
GDP per capita (1995 US$ at PPP)	18,940		

Source: Energy Data and Modelling Center, IEEJ.

*Ministry of Economic Development (New Zealand)

ENERGY DEMAND AND SUPPLY

PRIMARY ENERGY SUPPLY

New Zealand's total primary energy supply in 2000 was 18,296 ktoe. A variety of energy sources are used to meet these needs including oil (35 percent), gas (28 percent), geothermal (11 percent), hydro (12 percent), coal (6 percent) and others (7 percent). Self-sufficiency in 2000 was just over 81 percent.

New Zealand was 34 percent self-sufficient in oil in 2000. New Zealand's estimated remaining crude oil and condensate reserves comprise the Maui field (containing 71 percent of reserves at December 1999) and the Kapuni, Kupe and McKee fields. Production of crude oil and condensate was 1,608 ktoe in 2000, all from the Taranaki region. Although crude and condensate production has increased steadily since the early 1980s, there have been significant declines in the last few years, suggesting that this may have peaked in 1997 (due to the absence of significant new discoveries and developments in recent years). About one-third of local production is used for refinery feedstock, and about two-thirds is exported. New Zealand's only oil refinery is located at Marsden Point, near Whangarei. It produces petrol, diesel, aviation kerosene, fuel oils and bitumen.

New Zealand's natural gas production in 2000 was 5,057 ktoe, mainly in the Taranaki region. There were seven fields producing oil and gas in 2000, with the Maui field continuing to dominate (76 percent of gross production). Gas reserves are estimated to last until about 2014 at the expected rate of gas use, with the Maui field possibly running out around 2007. Around 40 percent of production is used in feedstock (methanol and petrochemical) industries, around 45 percent is used for electricity generation, and the balance is distributed to smaller users in the North Island.

New Zealand's total in-ground coal resources are estimated to be about 15 billion tonnes, of which 8.6 billion tonnes are judged to be economically recoverable. Coal production in 2000 was about 2,261 ktoe, mainly sub-bituminous. In 2000, around 43 percent of production was exported.

In 2000, New Zealand generated 37,856 GWh of electricity, around 72 percent of which came from renewable resources. Hydro (about 64 percent) was the most important source of generation followed by thermal (27 percent), geothermal (7 percent) and other (3 percent). Around 70 percent of hydro electricity is generated in the South Island, and all geothermal electricity is generated in the North Island. The balance, almost all of which is generated in the North Island, is generated by natural gas (23 percent), coal, wind and landfill gas. The largest electricity-using sector is industry (chiefly an aluminium smelter, iron and steel works, several pulp and paper mills and large dairy factories) which accounted for 44 percent of electricity demand in 2000.

New Zealand is likely to exhaust its existing gas reserves in the next 12 years or so depending on the rate of gas usage. Since natural gas imports are not feasible (except for LNG, which could be used as a backstop option), finding a replacement for gas-fired generation may mean increased coal-fired generation at the existing dual fuel (coal/gas) plant. It may also mean a greater role for renewables. Wood, "wastes", biogas and wind already make a small contribution to primary supply. Wind and geothermal power generation from better sites at 6 to 7 cents per kWh are the renewable resources that are likely to make appreciable contributions over the next 10 to 15 years.

Table 24 Energy supply & consumption (2000)

Total Primary Energy Supply	**(ktoe)**	**Total Final Energy Consumption**	**(ktoe)**	**Power Generation**	**(GWh)**
Indigenous Production	14,887	Industry Sector	3,411	Total	37,856
Net Imports & Other	3,409	Transport Sector	4,855	Thermal	10,320
TPES	18,296	Other Sectors	5,205	Hydro	24,045
Coal	1,066	TFEC	13,472	Nuclear	0
Oil	6,445	Coal	787	Others	3,491
Gas	5,057	Oil	5,899		
Others	5,729	Gas	2,827		
		Electricity & Others	3,958		

Source: Energy Data and Modelling Center, IEEJ (see http://www.ieej.or.jp/apec/database/selecttable.html)

FINAL ENERGY CONSUMPTION

Total energy consumption was 13,472 ktoe in 2000. Consumer energy is dominated by oil, comprising 5,899 ktoe per annum (44 percent), with electricity 2,856 ktoe (21 percent), gas 2827 ktoe (21 percent), coal 787 ktoe (6 percent) and renewables such as geothermal, wastes and wood making up the remainder (8 percent).

Transportation is the largest end use accounting for 36 percent of final consumption. The bulk of petroleum products used in New Zealand are consumed by this sector. The industrial sector is next with 25 percent, the residential/commercial sector uses 18 percent, the non-energy sector uses 17 percent, and agriculture consumes the remaining 3 percent. Energy consumption growth is strongest in the transportation and residential sectors.

POLICY OVERVIEW

New Zealand has undertaken comprehensive reform of the energy sector over the last 15 years or so. 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 has been established. Historical electricity tariff cross-subsidies have disappeared, and consumers now pay energy prices more closely reflective of the true cost of supply with increasing competition driving costs down. Areas where government interventions are still in place include natural monopolies (like electricity and gas transmission and distribution lines), environmental impacts, and barriers to energy efficiency uptake.

NOTABLE RECENT ENERGY DEVELOPMENTS

ELECTRICITY

The winter of 2001 saw significant electricity shortages in New Zealand. The shortages were caused by low rainfall and inflows into New Zealand's hydro-dominant generation system[4]. After the winter, the Government, by way of calling for public submissions, reviewed the functioning of the electricity system and electricity market to consider whether they can be improved, particularly in dry years. Recommended improvements included more advanced and better disclosure of system adequacy and forward prices, the development of real time spot market pricing and promotion of demand-side participation as well as arrangements for agreeing on and paying for new transmission investments to relieve constraints and the development of financial instruments to manage transmission risk.

More recently, the dry year problem, the impending depletion of the Maui gas field around 2007 and rising electricity demand have elevated interest in longer-term supply adequacy. After a surge of new generation capacity between 1996 and 2000 (around 1300 MW or roughly 10 years' supply capacity), the 2001-2005 period looks to have little capacity expansion. As a result, supply tensions could occur around 2005, especially in periods of low hydro inflow. Some proposals for gas-fired capacity are conditional upon securing adequate gas supplies at acceptable prices. A rising supply (cost) curve and the pressure for additional renewables continue to make hydro and wind power more competitive, and there are a number of significant proposals for both being investigated.

OIL AND GAS EXPLORATION/MINING

Several activities are underway to encourage much needed investment and exploration in oil and gas (see comments on supply issues under 'Electricity' above). In September 2002 the Government opened the Deepwater Taranaki Bidding Round. Five blocks are on offer totalling 42,000 sq km of unexplored acreage adjacent to the highly productive Taranaki basin. Planning is also underway for an onshore/offshore Canterbury Bidding Round (to be announced later in the year) and a new Taranaki Bidding Round.

There have been two new discoveries since 2000. The Goldie discovery within the Ngatoro mining permit has been flowing at up to 700 barrels of oil a day (currently shut in). In south Taranaki, the Kauri discovery looks likely to have the potential to produce oil and gas over multiple zones.

New Zealand has recently been ranked the 14th most attractive economy in the world for petroleum exploration investment according to the IHS Energy Group's PEPS ranking.

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4 Currently, hydro provides around 64 percent of generation. Hydro storage at around 8 weeks of demand is relatively limited. Winter is the period of highest demand coinciding with lowest inflows over the annual cycle.

ENERGY EFFICIENCY

The National Energy Efficiency and Conservation Strategy (NEECS) were released in September 2001. The Strategy's purpose is to promote energy efficiency, energy conservation, and the use of renewable sources of energy and progress New Zealand towards a sustainable energy future. The Strategy's two main aims are to improve New Zealand's economy-wide energy efficiency by 20 percent and increase the use of renewable resources by 30 PJ, which is about 8,300 GWh a year, both by 2012. The introduction of minimum energy performance standards, energy performance labeling and a revised Building Code, will assist in meeting the energy efficiency targets.

GHG AND CLIMATE CHANGE

New Zealand is a signatory to the Kyoto Protocol and ratified it on 10 December 2002. It has undertaken to reduce emissions of greenhouse gases during the 2008-2012 first commitment period to levels prevailing in 1990. A policy package was announced in April 2002 and was confirmed in October 2002. A key feature of the package is an emissions charge applied to fossil fuels and industrial process emissions. The charge will approximate the international emissions price, but be capped at NZ$25 per tonne of carbon dioxide equivalent. It will apply in the Kyoto Protocol's first commitment period 2008-2012 and not before 2007.

Greenhouse gas (GHG) and climate change issues are expected to significantly impact upon the New Zealand energy scene with the relative cost of fuels and the economics of electricity generation technologies shifting. Input cost structures in industry will change and these continue to cause concerns within the business community.

PETROLEUM PRODUCTS SPECIFICATIONS REGULATIONS

The Petroleum Products Specifications Regulations 2002 came into force in September 2002. Some of the new regulations will be introduced in phases until January 2006. Major changes to the petrol regulations include lowering the allowable levels of benzene and total aromatics, disallowing the use of MTBE, restricting the acceptable manganese content, and permitting the use of up to 10 percent ethanol by volume as a blending agent. For diesel, major changes include the lowering of allowable levels of sulphur, decreasing the maximum permissible density, increasing the minimum acceptable cetane number, and introducing standards for filterability and polycyclic aromatic hydrocarbon content.

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PAPUA NEW GUINEA

INTRODUCTION

Papua New Guinea (PNG) is an archipelago of some 600 islands located in the South West Pacific Ocean. Its largest contiguous part is the eastern half of the main island of New Guinea which borders West Papua, Indonesia and is geographically located north of Australia. Diversity of the population of 5.1 million is reflected in some 800 different spoken dialects. English is the official language of business and education.

The PNG economy may be slow to recover from current global economic slowdown influences. Current per capita GDP US$ 2,163 is slightly lower than the 1999 level. In 2000, real GDP at 1995 US dollars at PPP was estimated to be US$ 11.1 billion. Inflation is around 12.3 percent. PNG is a dualistic economy. Traditional agricultural crops of coffee, copra, cocoa and more recently, oil palm products and logging account for around 30 per cent of GDP.

Energy use per capita in PNG, at 0.2 toe per capita, is far below the APEC average of 1.5 toe per capita. Energy resources exports are very important for raising foreign exchange and funds for the national economy. In 2000, the energy industry accounted for approximately 12 percent of GDP, about 66.1 percent of total merchandise exports and employed about 1000 Papua New Guineans in upstream and downstream operations.

Table 25 Key data and economic profile (2000)

Key data		Energy reserves	
Area (sq. km)	462,840	Oil (Proven)	61.1 MCM*
Population (million)	5.13	Gas	425 BCM**
GDP Billion US$ (1995 US$ at PPP)	11.10	Coal (Recoverable)	0
GDP per capita (1995 US$ at PPP)	2,163		

Source: Energy Data and Modelling Center, IEEJ.

*Data for 1999 - UN Energy Statistics Yearbook.

**Ministry of Petroleum and Energy, 2002.

ENERGY SUPPLY AND DEMAND

PRIMARY ENERGY SUPPLY

In 2000, PNG's net primary energy supply was 988 ktoe, down 13.7 percent from 1999. This is possibly due to the global economic slowdown and negative GDP growth rates in the last three years that have seen many companies scaling down or closing their operations. Light crude oil and petroleum products accounted for 81.6 percent, gas for 12 percent while hydro and other fuels comprised the remaining 6.4 percent of primary energy supply. Around 90 percent or 887 ktoe of indigenous energy production is exported to other economies. An annual budget of US$ 20 million from private energy resource companies supports oil and gas exploration in PNG.

PNG's largest oil field, Kutubu, which has produced up to an average of 125,000 bbl/day of light crude since coming on stream in 1992 is in decline and now produces around 22,000 bbl/day. The development of the Gobe, SE Gobe and Moran fields means that current total production is around 65,000 bbl/day. The full development of the Moran field may add up to 11,000 bbl/day. Of the two small oil refineries planned, only the Port Moresby (Napanapa) plant has commenced construction.

PNG also has a small number of onshore natural gas fields with estimated reserves of totalling 425 BCM. In 2000, a small amount of gas was produced, 119 ktoe, and used for electricity generation. PNG is currently negotiating to sell some of this gas to Australia. To date, with approximately 75 petajoules (1791 ktoe) per year has been signed up out of planned an estimated 200 petajoules (4776 ktoe) per year that is required to make the proposed pipeline viablesigned up already.

As of 2000, total power installed capacity was 451.3 MW. PNG produced 1,290 GWh of electricity in 2000, down 1003 GWh from 1999 due to the scaling down of some mining operations. The sources of generation were hydro, 42 percent and thermal (gas and fuel oil), 58 percent (little changed from the mix in 1999). In 2000, 46.6 ktoe (down 33.4 ktoe) of energy were produced from hydro sources. There is little potential for expansion of economic large hydro due to a lack of significant demand near supply sources. However, there is greater potential for smaller schemes. Most power stations, thermal and hydro are owned and operated by the government-owned monopoly, PNG Power Ltd[5].

Table 26 Energy supply and consumption (2000)

Total Primary Energy Supply	(ktoe)	Total Final Energy Consumption	(ktoe)	Power Generation	(GWh)
Indigenous Production	1,875	Industry Sector	404	Total	1,290
Net Imports & Other	-887	Transport Sector	219	Thermal	748
TPES	988	Other Sectors	243	Hydro	542
Coal	0	TFEC	867	Nuclear	0
Oil	806	Coal	-	Others	0
Gas	119	Oil	766		
Others	63	Gas	-		
		Electricity & Others	101		

Source: Energy Data and Modelling Center, IEEJ (see http://www.ieej.or.jp/apec/database/selecttable.html)

FINAL ENERGY CONSUMPTION

In 2000, total end use energy consumption in PNG was 867 ktoe (an increase of 5 percent from 1999). By sector, industry at 46.6 percent (1999, 44 percent) is the largest end user, followed by transport at 25.3 percent (1999, 32 percent), with agriculture and residential/commercial at 28 percent (23 percent). By fuel source, petroleum products accounted for 88 percent of consumption (79 percent in 1999), electricity and others for 11.6 percent (21 percent in 1999).

In PNG, about 85 percent of the population live in rural areas, and electrification rates remain low. Petroleum products such as diesel or petrol are used in the transport sector and for the generation of electricity. Renewable energies such as small hydro, wind power and solar energy are not widely used, as they are expensive to install for general electricity use. In recent years, however, solar water heating equipment has been installed in more new buildings. Organisations such as Telikom and the Civil Aviation Authority also use photovoltaics for telecommunications and navigational aids purposes.

[5] The name was changed from PNG Electricity Commission to PNG Power Limited in 2001 due to planned privatisation. It has not been privatised yet as the new government is reviewing the status of all state owned entities. Source: http://www.PostCourier.com.pg (various)

POLICY OVERVIEW

In PNG, the national government has jurisdiction over energy matters including overall energy policy. The PNG Electricity Commission controls the generation and distribution of electricity, while energy policy matters and exploration and development of petroleum resources are determined and overseen by the Department of Petroleum and Energy.

Parliament is yet to approve the PNG National Energy Policy Statement. Acts of Parliament, such as the Electricity Commission Act, give authority to PNG Power Ltd for the generation, distribution and sale of electricity. All functions of the PNG Electricity Commission have been taken over by the new company without any liabilities so that it can be privatised. The Petroleum Act of 1972 and the Oil and Gas Act of 1998 gives the Ministry and Department of Petroleum and Energy authority over the licensing and development of petroleum and gas resources. The Price Control Act authorises the Ministry and Department of Finance and Treasury to set fuel prices and electricity tariffs.

The Energy Division of the Department of Petroleum and Energy implements policies and programmes, which are aimed at encouraging the adoption of new and affordable renewable energy technologies. The Energy Division and provincial governments work closely with PNG Power Ltd to increase the available amount of electricity capacity as and when demand growth justifies it.

NOTABLE ENERGY DEVELOPMENTS

Recent energy developments of note in Papua New Guinea include the following:

- The Rural Electrification Policy Document, completed in June 2001 will under undergo another review process and therefore it is yet to be approved by the government, is aimed at improving rural access to electricity;
- The former government's aim to privatise the State utility, PNG Electricity Commission, is currently on hold as directed by the new government;
- The PNG to Queensland (Australia) gas pipeline project is still under negotiation; and
- Inter Oil of Canada has commenced construction of the 32,500 bbl/day oil refinery.

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PERU

INTRODUCTION

Peru is located on the Pacific Ocean coast of South America. It shares borders with Ecuador and Colombia to the north, Brazil and Bolivia to the east, and Chile to the south. Its 26 million people are spread over 1,285,216 square kilometres, but 72 percent live in urban areas. It has three main regions and climates: the western desert coastal plains, the cold central Andes mountains, and the tropical eastern Amazon jungle. Geographically, 53 percent of the population live in the coastal region, 37 percent in the mountainous region and 10 percent in the Amazonian region. Peru is a major exporter of metals; it is the world's second largest silver exporter after Mexico and is also among the top five exporting economies for copper, zinc, tin and lead.

Peru's GDP in 2000 was US$ 118.3 billion while GDP per capita was US$ 4,611 (both in 1995 US$ at PPP). While the economy showed signs of recovery in 1999 and 2000, it grew only 0.2 percent in 2001. Contributing to the slowdown were political uncertainty following the presidential elections, contraction of domestic demand with rising unemployment, political and economic crises in neighbours Argentina and Brazil, the weakness in many economies after September 11, and declining prices for exported metals. A major bright spot for the economy in 2001 was the Antamina copper and zinc project, which helped the mining sector grow by more than 13 percent and reignited growth by prompting new foreign investments in other mining projects.

Peru is now a net importer of energy. Of the total energy imported, more than 90 percent is crude oil used as refinery feedstock; domestic crude is not of adequate quality for such feedstock. The remainder of Peru's energy imports consist of coal. Its energy reserves in 2001 included approximately 51 MCM of oil, 245 BCM of gas and 59 Mt of coal.

Table 27 Key data and economic profile (2000)

Key data		Energy reserves*	
Area (sq. km)	1,285,216*	Oil (proven)	51.4 MCM
Population (million)	25.66	Gas (proven)	245.1 BCM
GDP Billion US$ (1995 US$ at PPP)	118.32	Coal (proven)	58.7 Mt
GDP per capita (1995 US$ at PPP)	4,611		

Source: Energy Data and Modelling Center, IEEJ.

*December 2001 data from Ministry of Energy and Mines, Peru.

ENERGY SUPPLY AND DEMAND

PRIMARY ENERGY SUPPLY

Peru's total primary energy supply in 2000 was 11,047 ktoe, of which oil comprised the biggest share (67 percent). Natural gas (14 percent), hydro (13 percent) and coal (6 percent) were the other main sources of energy. Peru imported about 29 percent of its energy requirements (mostly oil) in 2000, almost twice the 15 percent share of energy needs imported the previous year.

Owing to a lack of new oil discoveries, production of crude oil declined by 7 percent in 2000 and 3 percent in 2001 to an average of 96,000 bbl/d. Current production areas are located in the northern jungle, the coast and offshore. The government estimates that Peru will require US$ 165 million per year in drilling investments over five years to maintain proven oil reserves.

Unfortunately, initial exploration efforts in Peru's offshore coastal basins have yielded poor results, discouraging further investment by oil companies.

The Norperuano pipeline from the Amazon to the Pacific Ocean is being used to meet domestic oil demand. The pipeline has a capacity of 200,000 bbl/d, but only 30 percent is being used. A scheme to use the line to import crude oil from southern Ecuador is being considered.

Peru's gas production grew about 5 percent in 2000 and 4 percent in 2001, to 1.7 BCM. But Peru could potentially produce far more gas than it does today as domestic gas demand and gas export markets grow. Upstream operations recently began at the Camisea field, one of the largest in South America, which was first discovered in Peru's southern jungle in the early 1980s. The field is expected to produce 10 MCM/d of gas and 0.004 MCM/d of condensate once fully operational. It should generate revenues for Peru of US$ 5-6 billion in royalties and taxes over the next 30 years. The two reservoirs in this area are estimated to contain 230 BCM of gas and over 90 MCM of condensate. The power generation and industrial sectors are expected to be major gas consumers.

Table 28 Energy supply & consumption (2000)

Total Primary Energy Supply	(ktoe)	Total Final Energy Consumption	(ktoe)	Power Generation	(GWh)
Indigenous Production	7,832	Industry Sector	3,336	Total	19,923
Net Imports & Other	3,215	Transport Sector	3,386	Thermal	3,747
TPES	11,047	Other Sectors	2,478	Hydro	16,176
Coal	630	TFEC	9,200	Nuclear	0
Oil	7,425	Coal	430	Others	0
Gas	1,547	Oil	7,225		
Others	1,444	Gas	1		
		Electricity & Others	1,543		

Source: Energy Data and Modelling Center, IEEJ (see http://www.ieej.or.jp/apec/database/selecttable.html)

As of December 2000, installed electric generating capacity in Peru was 6,066 MW, up from 2,385 MW in 1985, and 73.5 percent of the population had access to electricity. Hydropower accounts for 81 percent of electricity generation but only 47 percent of electric generating capacity, down substantially from 59 percent in 1985. About 7 percent of power is generated from residual fuel oil, 6 percent from diesel, 4 percent from natural gas and 2 percent from coal.

In October 2000, a new north-south transmission line unified the former central-north (SICN) and southern (SIS) grids to form the National Interconnected Electrical System (SEIN). In 2000, of the 19,923 GWh of electricity generated in the economy, 92 percent was delivered through SEIN and the remaining 8 percent was delivered through several smaller isolated systems (SSAA).

FINAL ENERGY CONSUMPTION

Between 1980 and 2000, final energy consumption in Peru increased by 48 percent while energy production fell by 29 percent. In 2000, final energy consumption in Peru amounted to 9,200 ktoe, of which transport consumed 37 percent and industry 36 percent. Petroleum products dominated end use consumption, accounting for 79 percent of demand in 2000.

POLICY OVERVIEW

Peru's economy is becoming more market-oriented. Virtually all trade, investment and foreign exchange controls were eliminated in 1990. The mining, electricity, hydrocarbons and telecommunication industries have been partially privatised. In particular, the state oil company, Petroperu, was partially privatised in 1993 and has become Perupetro. Several laws affirm that "national and foreign investment are subject to the same terms" and have permitted foreign companies to participate in almost all economic sectors.

The Electricity Concessions Law, passed in 1992, allows private firms to invest in power generation, transportation and distribution. The state utility ElectroLima and the bulk of state utility ElectroPerú were privatised soon after the law was implemented. Another law, passed in 1997, promotes competition in the power sector by prohibiting control of more than 15 percent of power generation, transportation or distribution by any one firm. The government can block acquisitions to ensure that private companies do not gain excessive market power. The private sector, including foreign companies, today controls about 65 percent of generating capacity and 72 percent of the distribution system. The government retains ownership of key hydroelectric plants.

The Andean Community (ANCOM) was established by Bolivia, Colombia, Ecuador, Peru and Venezuela in 1996. Its purpose is to create a common market similar to the European Union. ANCOM may bring about a more integrated regional energy market among Andean economies.

NOTABLE ENERGY DEVELOPMENTS

PRIVATISATION PROGRAMME

The government that took office in July 2001 stepped up privatisation activities in the energy sector that had slowed under the two previous governments. While opponents claim that privatisation contributes to unemployment and high energy tariffs, the government believes that it increases investment and lowers prices. Active promotion of private investment helped to bring about the July 2001 sale of the Electroandes Power Company to PSEG Global of the US. The Talara oil refinery and the Mantaro hydroelectric plant are also being considered for privatisation. However, violent demonstrations and riots in June 2002 in the cities of Arequipa and Tacna, which followed the government's announcement of the sale of the Egasa and Egesur electric utilities to Belgium's Tractebel, may well force delay or reconsideration of privatisation plans.

ADVANCES IN THE CAMISEA GAS PROJECT

Pluspetrol SA of Argentina is leading the consortium that owns the concession for upstream operations at the Camisea gas project. Pluspetrol believes that Camisea could yield as much as fields in neighbouring Bolivia, where recent exploration and development activities have uncovered reserves of 1400 to 1700 BCM. Techint SA, also from Argentina, operates a transportation concession to deliver gas from Camisea to the city of Lima, and Belgium's Tractebel SA heads the consortium that will handle distribution in Lima. Additional reserves could make Peru a regional gas exporter, with potential customers in Mexico, the western United States and Brazil.

The government, in cooperation with private industry, is carrying out an aggressive plan to expand gas utilisation in Peru that could lead to a gas grid linking all communities with more than 5,000 inhabitants and help reduce dependence on oil imports nationwide. Also envisioned is a greater use of compressed natural gas (CNG) in transportation, along the lines of Argentina's programme which has yielded a fleet of 800,000 CNG vehicles.

Pluspetrol has drilled its first well, San Martin 1, which was tested in November 2002. A second well was also to be completed in 2002, and three more wells are planned in the same area. Pluspetrol hopes to start commercial operations in April 2004 even though the original concession contract calls for operations to begin in August of that year.

Work has also started on the construction of a gas pipeline that would distribute gas from the Camisea project to the major Peruvian cities of Lima and Callao. This would serve as a trunkline for distribution to other areas in the future. The government estimates that electricity tariffs could decrease by 30 percent within 10 years as a result of increased gas availability in the economy.

ENCOURAGING NEW EXPLORATION

The expense and low probabilities of major findings of new oil reserves has recently discouraged oil producing contractors from investing in exploration activities. For that reason, the Ministry of Energy and Mines has proposed a new incentive that allows oil producers that invest in exploration to lower the rate of royalties paid to the government. The legal modification has already been approved in 10 oil exploration contracts.

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THE PHILIPPINES

INTRODUCTION

The Philippines, located in the western rim of the Pacific Ocean, comprises 7,107 islands and islets spread over a distance of 1,854 kilometres from the boundaries of Chinese Taipei in the north to the Indonesian archipelago in the south. Total land area is about 300,000 square kilometres with a population of 75.6 million in 2000.

Gross domestic product (GDP) in 2000 grew by 4 percent at US$ 296.6 billion dollars at 1995 purchasing power parity (PPP). GDP per capita is still quite low at US$ 3,924 (1995 US$ at PPP) and energy consumption per capita is one of the lowest in the APEC region.

In 2001, the Philippines experienced an impressive improvement of the economy with GDP growing at 3.4 percent. The change in economic climate has been brought about by improved agricultural yields, increases in domestic consumption and also the benefits of the Malampaya natural gas field coming on stream. A stable political environment under the administration of President Macapagal-Arroyo has improved foreign investors' confidence and has resulted in a surge of 171 percent in foreign investment to $3.4 billion.

The Philippines' proven indigenous energy resources are small with only about 24 million cubic metres (MCM) of crude oil, 107 billion cubic metres (BCM) of natural gas and 399 million metric tonnes of coal, mainly lignite. As an effort to reduce expenses on imported oil, the Philippine government has placed expanding gas usage for power generation as a priority.

Table 29 Key data and economic profile (2000)

Key data		Energy reserves*	
Area (sq. km)	300,000	Oil (Proven)	24 MCM
Population (million)	75.58	Gas (Proven)	107 BCM
GDP Billion US$ (1995 US$ at PPP)	296.60	Coal (Recoverable)	399 Mt
GDP per capita (1995 US$ at PPP)	3,924		

Source: Energy Data and Modelling Centre, IEEJ.

*Philippine Department of Energy (DOE).

ENERGY SUPPLY AND DEMAND

PRIMARY ENERGY SUPPLY

In 2000, the total primary energy supply (excluding traditional fuels) amounted to about 33.3 Mtoe. The main energy sources were oil, 50 percent, geothermal, 37 percent and coal, 12 percent. 60 percent of energy requirements were imported. Indigenous energy production was around 13.2 Mtoe, comprising mostly of hydro and geothermal electricity generation. Of the total oil supply, 99.7 percent was sourced from abroad.

Average oil production up to early 2001 was only 1,000 bbl/d, but by October, production had increased 20-fold due to the development of the deep-sea condensate deposit in the gas and oil Malampaya field. However, this production is still around only 5 percent of current demand of around 356,000 bbl/d. APERC projects oil consumption to increase by 4.1 percent per annum due to increased demand in most sectors resulting from healthy economic growth.

About 7.3 Mt of the 8.6 Mt of coal consumed in 2000 was imported, mostly from Indonesia, China and Australia. Historically, the Philippine coal industry has been supported by regulations. However, World Trade Organization (WTO) regulations require the Philippines to lift import restrictions. This and other factors, including the increased use of natural gas for electricity generation and opposition from pressure groups, are likely to pose challenges to the development of the domestic coal sector.

The government has announced a number of coal-fired thermal power plants as candidates for conversion to natural gas, including the 900 MW Sucat 1 and 2 plants in South Manila. Domestically produced coal will be encouraged in other uses. DOE plans studies to determine the viability of mine-mouth coal-fired plants using clean coal technology.

Gas production and use was small at 87 ktoe in 2000. Development of natural gas reserves in the Malampaya-Camago fields is in progress, and gas use for electricity generation is expected to increase sharply in the next few years. In November 2000, service contractor Shell Philippines Exploration BV (SPEX) completed the construction of a 504 km gas pipeline that will be used to transport natural gas from the wellhead to an onshore gas processing plant. The gas will fuel three power plants with a combined capacity of 2,700 MW located some 500 km away.

Electricity production in the Philippines was about 52,527 GWh in 2000. The bulk of generation came from thermal sources, mostly coal and fuel oil, 49 percent, geothermal, 36 percent and hydro, 15 percent. Total installed power generating capacity reached 13,185 MW. APERC projects electricity demand growth to be around 6 percent per annum to 2020. This implies that significant additional generation capacity will be required.

The Philippines Energy Plan indicates that total primary energy consumption is expected to grow at an average yearly rate of 5.6 percent from 2002 to 2004 and 6.5 percent from 2005 to 2011.

Table 30 Energy supply & consumption (2000)

Total Primary Energy Supply	(ktoe)	Total Final Energy Consumption	(ktoe)	Power Generation	(GWh)
Indigenous Production	13,218	Industry Sector	3,431	Total	52,527
Net Imports & Other	20,046	Transport Sector	8,319	Thermal	25,865
TPES	33,264	Other Sectors	5,422	Hydro	7,799
Coal	4,119	TFEC	17,171	Nuclear	0
Oil	16,629	Coal	650	Others	18,863
Gas	87	Oil	13,378		
Others	12,429	Gas	0		
		Electricity & Others	3,144		

Source: Energy Data and Modelling Center, IEEJ (see http://www.ieej.or.jp/apec/database/selecttable.html)

FINAL ENERGY CONSUMPTION

Final energy consumption in the Philippines was about 17.2 Mtoe in 2000. Transportation was the largest end use consumer, accounting for 48 percent of energy, followed by residential and commercial use at 32 percent and industry at 20 percent. Due mainly to the importance of the transportation sector, petroleum products dominated final energy use, making up 78 percent of total demand. Electricity was next with 18 percent, and coal comprised 4 percent.

POLICY OVERVIEW

The major energy reforms and developments being carried out in the Philippines include reducing the Philippines' dependence on imported oil, restructuring and deregulating the power sector to improve efficiency and lower prices, establishing the Philippine natural gas industry, implementing projects to electrify isolated villages and diversifying the relative composition of fuel consumption. The Philippines Energy Plan (PEP) 2000-2009 has the following objectives: to increase domestic energy production with a target of at least 50 percent energy self-sufficiency (currently around 40 percent) by 2004; to accelerate completion of the "O Ilaw" rural electrification program, which stipulates 100 percent electrification by 2004; to implement structural reforms which promote private-sector investment in order to meet the projected requirements in electricity supply; to create a policy framework for the natural gas industry; and to continue deregulation of the downstream oil sector.

The Philippine government is developing a policy framework for the emerging gas industry that foresees the government's role as that of facilitator while attempting to ensure competition. Domestic development is to be encouraged, but competition from imported gas also is to be allowed. Gas supply to wholesale markets will have market-set prices, while prices for captive markets and small consumers will be regulated.

OIL

SPEX has committed $4.5 billion to Malampaya combined oil/natural gas project and anticipates crude oil production of 35,000-50,000 b/d by 2003. Nido Petroleum, Philippines National Oil Company Exploration Corp., Trans-Asia Oil, Unocal Corp. and Philodril are leading six new offshore exploration projects. The prospects seem quite positive with estimates of reserves totalling almost one billion barrels of oil located in these exploration areas.

DOWNSTREAM

Petron, Pilipinas Shell (Royal Dutch/Shell's Philippine subsidiary), and Caltex (Philippines) are the three companies dominating the downstream oil industry. Petron is the largest oil refining and marketing company. Overall, refineries in the Philippines run at around 80 percent capacity, and new refinery construction is not yet in great demand.

Currently, the Philippines enjoy the lowest fuel prices among oil-importing Asian economies due to the deregulation of the oil market which begun in 1998. Deregulation has resulted in significant price swings of fuel in response to volatile world oil prices and exchange rates. As in Thailand and Indonesia, rapid and significant price rises have resulted in public discontent. In the Philippines, they have triggered public calls for explicit price controls. However, the government has remained committed to deregulation. In December 1999, the Supreme Court upheld the economy's deregulation program despite opposition from the NPPAP (New Players Petroleum Association of the Philippines), which complained that its members had not yet penetrated at least 30 percent of the market.

NATURAL GAS

The Malampaya Gas-to-Power Project (MGPP) signals the birth of the natural gas industry in the Philippines. This development is guided by DOE Circular 95-06-006, issued in the 1990s, which provides for integration of natural gas into the energy supply mix. The Circular mandates the DOE to provide policy direction and regulation, encourage private sector participation, and promote the policy of indigenous energy resource utilisation to stabilise energy prices.

President Arroyo has made some policy pronouncements towards the promotion of the natural gas industry in the economy as follows:

- Opening access for all land-based gas pipeline networks to ensure the inflow of investments in the area;

- Encouraging conversion of certain National Power Corporation (NPC) plants into gas-fired power plants;
- Continuing advocacy for the use of CNG for public transport vehicles; and
- Promoting development and use of small gas fields for non-power applications.

NOTABLE ENERGY DEVELOPMENTS

In pursuing energy policy focussed on sustainable development and global competitiveness, the Philippines has been reviewing existing policies and carrying out structural reforms particularly in the electric power sector and the downstream oil and gas sectors.

DEVELOPMENT OF THE NATURAL GAS INDUSTRY

Latest steps in the development of the Philippine natural gas industry are as follows:

DOWNSTREAM NATURAL GAS

- Executive Order No. 66, promulgated on 18 January 2002, designated DOE as the coordinating agency for efforts to establish a successful and robust natural gas industry. The DOE Circular on Interim Rules and Regulations Governing the Transmission, Distribution, and Supply of Natural Gas, issued on 27 August, provides economic and technical guidelines for the construction and operation of transmission and distribution pipelines and related facilities. The DOE is pushing for passage of the Natural Gas Bill to institutionalise regulatory mechanisms and suggest measures to address concerns that are beyond the purview of existing laws.

INDUSTRIAL GAS USE

- Clustered industries along the pipeline routes in the Batangas-Manila area are targeted for conversion to natural gas for their process heat, air conditioning and perhaps even power requirements. The main focus at present is on construction of an 80 to 100 km pipeline to bring natural gas from Batangas to Metro Manila.

GAS FOR TRANSPORT

- It has been proposed to use natural gas for public transport, including jeepneys, taxis and buses, especially in Metro Manila.
- In June 2002, the PNOC-Petronas Natural Gas Vehicle Development Project was launched. This followed the signing of a memorandum of understanding (MoU) between PNOC and Petronas NGV Sdn Bhd in Kuala Lumpur in May 2002 through which six Enviro 2000 vehicles were brought from Malaysia.
- The DOE is pursuing the conversion of 100 public buses to CNG, as well as completion of an initial CNG refilling facility in Metro Manila, by 2003.

DOWNSTREAM OIL INDUSTRY DEREGULATION

The downstream oil industry sector operates under the Republic Act (R.A.) 8479, or the Downstream Oil Industry Deregulation Act of 1998. As of June 2002, 73 new entrants were participating in the downstream oil industry, and total investments by these enterprises amounted to P16.091 billion. New entrants had 11.4 percent of the downstream market by the end of 2001.

RESTRUCTURING OF THE POWER INDUSTRY

The Arroyo Administration continues to seek ways to lower the costs of electricity to consumers. The Electric Industry Reform Act (EIRA) of 2001, or R.A. 9136, was enacted in June 2001. The Act's main objective is to reduce electricity rates by encouraging competition and improving efficiency in the industry. Two major reforms embodied in R.A. 9136 are the restructuring of electric power industry and privatisation of the National Power Corporation (NPC or Napacor). Restructuring calls for separation of the power sector into generation, transmission, distribution and supply components. Privatisation of Napocor involves selling the state-owned power firm's generation assets to private investors and awarding the operation and maintenance of the transmission assets to a concessionaire. A major remaining hurdle in the process involves the transfer of some existing Napocor debt to the Government. Implementing Rules and Regulations (IRR) for the Reform Act became effective in March 2002.

Rules for the Wholesale Electricity Spot Market (WESM), which the Reform Act calls for, were promulgated and became effective in July 2002. These rules provide a mechanism for determining the price of electricity not covered by bilateral contracts between sellers and buyers of electricity. They were drafted and with advice from public consultations that the DOE begin in November 2001. Next steps include: (1) creation of a Technical Working Group (TWG) for WESM composed of the government and industry participants; (2) establishment of an Autonomous Group Market Operator (AGMO) to run the WESM; (3) a petition to the Energy Regulatory Commission for approval of the WESM price determination methodology and market fees; and (4) procurement of an interim Market Management System (MMS). The WESM is a market where electricity will be traded by generating companies, distribution utilities, suppliers, bulk consumers/end-users, and other similar entities authorised by ERC.

STATE OF THE NATION ADDRESS

In her State of the Nation Address at the opening of the second session of the 12th Congress (July 2002), President Arroyo presented a ten-point plan that would reduce electricity rates by (1) reflecting the true cost of service in the rates; (2) introducing price incentives to stimulate demand; (3) optimising the utilization of generation capacity to minimise costs; (4) establishing a competitive wholesale generation market; (5) accelerating open access to give end-users the power of choice; (6) requiring efficient performance of distribution utilities; (7) strengthening the electricity cooperatives; (8) reducing independent power producers' (IPP) contract costs; (9) exploring financial engineering to reduce stranded costs; and (10) enhancing the Energy Regulatory Commission's (ERC) capability to promote consumer welfare.

IPP CONTRACTS REVIEW

IPPs are recognised as long term partners in developing a competitive energy sector. The DOE and the Power Sector Assets and Liabilities Management (PSALM) Corporation have initiated discussions with IPPs to review certain terms of the IPP contracts. The objective is to seek mutually acceptable resolutions that would benefit both parties. The IPPs aim to enjoy stable and predictable returns while the government seeks to lower the overall cost of electricity. In the initial review, it was found that of 35 contracts, 6 had no legal or financial issues to address, 11 had financial issues, 16 had legal and financial issues, and 2 had remedial policy issues.

RURAL ELECTRIFICATION

Under the P14 billion O'ilaw Program, the DOE is working with its attached agencies to electrify all villages by 2006. As of June 2002, 85 percent of all villages had access to electricity.

RENEWABLES

According to the Philippine government, the Philippines is the world's second largest producer of geothermal power with a capacity of 1,931 MW. There are plans to increase capacity to 2,921 MW in which case the Philippines could surpass the US to become the world's largest producer.

Solar electrification is being considered by the government, particularly in villages where connections to the main grid are not feasible or are too costly. In March 2001, the Philippine and Spanish governments signed a $48 million contract with BP to supply solar power to 150 villages.

Wind resource assessments conducted by the United States Department of Energy reveal that wind resources in the Philippines have high potential to generate a significant amount of power. However, the wind power industry is in its nascent stages with just a few developments.

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RUSSIA

INTRODUCTION

Russia has the largest land area of any economy in the world – about 17 million square kilometres. The overall population density is low – only 9 persons per square kilometre, with the northern and eastern regions very sparsely populated. The population declined from 148.39 million in 1990 to 145.6 million in 2000. Annual energy consumption is around 5.3 toe per capita, compared with an APEC average of 1.5 toe per capita.

After a decade of economic contraction of about 40 percent compared to the 1990 GDP level, the Russian economy began to grow again at the beginning of 1999, boosted by higher oil prices and the stimulating effect of the 1998 rouble devaluation. In 2000, GDP grew 8.3 percent, industrial production grew 10.3 percent and investment was up 17.2 percent. GDP in 2000 was estimated to be US$ 1,134 billion (at 1995 purchasing power parity dollars). Inflation has been kept under the official target of 16 percent for 2000. The official unemployment rate is about 8 percent.

Russia has abundant natural energy resources, possessing the world's largest proven reserves of gas (48.1 TCM – 32.1 percent of the world total in 2000), 4.6 percent of the world's proven oil reserves (6.7 billion tonnes in 2000) and 15.9 percent of the world's coal reserves (157 billion tonnes in 2000). The economic potential of hydropower is estimated at 852 TWh per year, almost 20 percent of which has been developed. Economic reserves of uranium ore comprise about 14 percent of the world total.

The energy sector is very important to Russian economic development. In 2000, the energy industry accounted for approximately 12 percent of domestic GDP. At the same time its share of federal budget revenues was about 50 percent. The employment share was only 4 percent of the total workforce. Oil and gas exports comprised 55 percent of total merchandise exports in 2000.

Table 31 Key data and economic profile (2000)

Key data		Energy reserves*	
Area (sq. km)	16,888,500	Oil (Proven)	7,774 MCM
Population (million)	145.56	Gas	48,140 BCM
GDP Billion $ (1995 $ at PPP)	1,134.37	Coal (Recoverable)	157.0 Bt
GDP per capita (1995 US$ at PPP)	7,793		

Source: Energy Data and Modelling Center, IEEJ.

*The BP Statistical Review, 2002.

ENERGY DEMAND AND SUPPLY

PRIMARY ENERGY SUPPLY

In 2000, Russia's total primary energy supply was 872 Mtoe. This total comprised 48 percent natural gas, 22 percent crude oil and petroleum products, 20 percent coal, 4.5 percent nuclear and 3.5 percent hydro. Russia is a large net exporter of energy. In 2000, 37 percent of energy production was exported, mainly to Eastern and Western Europe. Currently, Russia is developing new eastern energy export routes.

OIL

In 2000, Russia produced 323.6 Mtoe of crude oil and gas condensate. Net exports of crude and petroleum products totalled 144.4 Mtoe (44.6 percent).

Currently, the oil industry is highly profitable because of high world oil prices. The main oil province of West Siberia produces about 70 percent of total crude oil. New prospective oil provinces are located in the Timano-Pechora region, East Siberia, the Far East and North Caspian offshore.

Annual average refinery capacity was 257 Mt. The load factor was 62 percent in 2000. It is steadily increasing towards the optimal target level of 80-85 percent. Refining degree (the share of light petroleum products in refinery output) is rising as well, reaching 71 percent in 2000.

NATURAL GAS

Natural gas production in 2000 totalled 470 Mtoe. Net exports accounted for 156 Mtoe or 33 percent of production. Currently, 11 percent of exports go to the Commonwealth of Independent States (CIS) economies Ukraine, Belarus, Kazakhstan, Moldavia, and 89 percent to Eastern and Western European economies.

Since the 1990s production has exceeded reserve additions due to insufficient investment in the development of new fields and pipelines. New resource bases are located in remote regions without infrastructure needed to start upstream operations. They are: the Barents Sea offshore (Schtokmanof field), East Siberia (Kovykta), Yakutia and Sakhalin offshore.

COAL

In 2000, Russia produced 108 Mtoe of coal, 65 percent of the 1990 level but 3.5 percent higher than in the previous year. Hard coal production was 66.5 percent of the total with the balance of 33.5 percent being lignite. The main coal production is located in Eastern Russia – the Kansk-Achinsk and Kuznetsk regions. Perspective coal basins have been found in more remote areas of Eastern Siberia, South Yakutia and the Far East. The government envisages a greater role for coal in power generation and in the overall national energy balance.

ELECTRICITY

Russia produced 876,032 GWh of electricity in 2000. Of this total, 66 percent was produced from thermal fuels (gas, coal and fuel oil), 19 percent by hydro and 15 percent by nuclear.

Hydropower performs an important function to regulate peak loads in the unified power grid. The largest hydro stations and most prospective hydro resources are located in southern Siberia; however, the capital costs of new hydro are prohibitively high. There is significant untapped hydroelectric potential in Eastern Russia with some large plants to be built in the next 10 years: the Boguchanskaya station in East Siberia, and the Bureya, Ust'-Srednekanskaya, and Vilyi stations in the Far East.

In 2000, Russia operated 30 nuclear reactors with installed capacity of about 22.2 GW. They are mainly located in the European part of Russia.

ENERGY DEMAND

In 2000, total final energy consumption in Russia was 772.6 Mtoe. By sector, 35 percent was industry, 39 percent residential and commercial, 19 percent transport and 3 percent agriculture. Fuel shares for total final energy consumption were 6 percent coal, 20 percent petroleum products, 27 percent gas and 12 percent electricity and 33 percent heat. Due to the harsh climate, the most important energy use is for space heating, comprising about 40 percent of total final consumption.

There are some clear signs of inefficient energy use in the Russian economy. The primary energy intensity of GDP rose 18 percent from 1990 to 1996 and then declined 12 percent by 2000. Final energy intensity of GDP (at 345 toe per million 2000 US$ at PPP) is highest among the APEC economies. The traditional energy-intensive industrial structure with its aging capital stock has not changed greatly, due to the lack of structural reforms and investment. Structural shifts to less energy-intensive services and high-technology industries are considered as a major policy direction to encourage energy savings, along with energy efficiency measures in existing industries. According to various estimates, Russia has an untapped energy savings technical potential of 35 to 45 percent of total energy consumption.

Table 32 Energy Consumption & Supply (2000)

Total Primary Energy Supply	**(ktoe)**	**Total Final Energy Consumption**	**(ktoe)**	**Power Generation**	**(GWh)**
Indigenous Production	1,168,380	Industry Sector	192,113	Total	876,032
Net Imports & Other	-296,425	Transport Sector	37,177	Thermal	580,000
TPES	871,955	Other Sectors	543,323	Hydro	165,400
Coal	107,734	TFEC	772,613	Nuclear	130,600
Oil	186,583	Coal	47,627	Others	32
Gas	320,511	Oil	101,717		
Others	257,127	Gas	211,466		
		Electricity & Others	411,803		

Source: Energy Data and Modelling Center, IEEJ (see http://www.ieej.or.jp/apec/database/selecttable.html)

POLICY OVERVIEW

MARKET LIBERALISATION

Oil and coal markets in Russia were deregulated in the 1990s. Market liberalisation is a strategic direction for development of both power and natural gas industries. One of the main issues is a gradual move from state-regulated energy prices to free market pricing. For domestic energy markets as a whole, perhaps the most urgent problem to resolve is the existence of price distortions between oil product prices, coal prices and artificially low state-regulated gas prices.

In October 2002, Prime Minister Mikhail Kasyanov pointed out that Russia may deregulate contestible portions of the electricity and gas markets within the next five years. The government would likely keep control over tariff-setting policy and natural monopoly elements of these markets.

STRATEGIC OIL RESERVE

The idea to create a strategic oil reserve was debated in the federal parliament (Duma) in the early 1990s, but interest in the idea subsided after the swift privatisation of state oil assets. Debate over the reserve was revived in January 2002, when oil companies were suffering from an oversupply on the domestic market due to government export limitations which had resulted from an agreement with OPEC. Industry experts recommended that the government exploit the opportunity to buy cheap oil and sell it later at a profit while supporting demand at the same time.

At the US-Russia energy summit in Houston, 1-2 October 2002, Energy Minister Igor Yusufov said that Russia needed an oil reserve of 50 Mt. Infrastructure construction and filling the reserve would cost an estimated US$20 billion to $25 billion. It could be used to create optimal conditions for Russia's oil industry against a background of severe price volatility. The US agreed to provide Russia with expertise on creating and managing the reserve.

ENVIRONMENTAL POLICY

At the 2002 World Summit on Sustainable Development in Johannesburg, Russian Prime Minister Mikhail Kasyanov made the following statement: "Russia has signed the Kyoto Protocol and we are now preparing its ratification. We consider that ratification will take place in the very nearest future." Russian ratification would virtually ensure the treaty is implemented despite its rejection by the United States. The potential size of Russian carbon dioxide quota trading is estimated at a 300-500 million tonnes annually for the 2008-2012 first commitment period.

EASTERN REGIONAL ENERGY POLICY

The Russian Energy Ministry has elaborated a number of measures aimed at increasing the production of fuel and energy resources in the Far Eastern Federal District and in Eastern Siberia, where energy is in short supply. The Far East in particular experiences continual power shortages. The Energy Ministry said that it plans to work out a unified program next year for developing gas resources and associated gas transport and distribution systems in the eastern part of Russia.

The region's need for energy resources can be satisfied from an increase of oil and gas production within production sharing agreements, in particular, projects Sakhalin-1, Sakhalin-2 and new projects Sakhalin-mainland and Sakhalin-3. To improve energy supply in the Kamchatka region, the Ministry is considering the construction of a gas pipeline to Petropavlovsk-Kamchatsky and the conversion of Kamchatka's power plants from the costly fuel oil currently used to natural gas. The plan also calls for intensive development of the territory's own fuel resources by exploiting new gas fields in the Sakha republic and Sakhalin and alternative sources such as hydroelectric power, geothermal power and wind.

One of the priority directions is the construction of an oil pipeline from Angarsk to Nakhodka. In the medium-long term perspective (2010-2015) it is planned to complete the construction of the Sakhalin-Komsomolsk-Khabarovsk gas and oil pipelines.

ENERGY COOPERATION

The Russian oil pipeline monopoly 'Transneft' is carrying out a feasibility study for a 3,765 km Angarsk-Khabarovsk-Nakhodka oil export pipeline with a capacity of 50 Mt per year targeting Pacific Rim markets. The time frame for the project is 2005-2010.

Several recent cooperative activities involve China:

- In 2002, Russia and China agreed to speed up construction of a 2,400 km oil pipeline from the Siberian region of Irkutsk to China's north-eastern oil centre of Daqing. The pipeline is projected to transport 20-30 Mt per year of Russian oil into China after 2005. The main supplier will be the 'YUKOS' company.
- Russia is now building the Tian-Wan nuclear power plant in China, which will have two power units with Russian VVER-1000 light water reactors.
- The Russian Gazprom gas monopoly belongs to an international consortium that expects to complete a 4,200 km gas pipeline from west China towards Shanghai in 2004. The pipeline will have an annual throughput capacity of 12 BCM. Gazprom has set up a representative office in Beijing in 2001, with a view to expanding its business in China. The company has officially acquired a status of coordinator of all eastern Russia natural gas projects.
- Joint development of the 1,900 BCM Kovykta gas field is a subject of a trilateral China-Korea-Russia feasibility study.

Energy cooperation is also underway with the United States:

- In July 2002 Russia made direct oil shipments to the US market for the first time. Government officials and oil industry representatives estimate the potential supply at up to 1 Mbd, nearly 10 percent of US imports. However, there is a need to modernise and upgrade port facilities and improve the pipelines to serve the new export routes.

- The US Department of Energy has agreed to fund a study of East Siberian oil reserves, which are largely untapped, as Russian oil companies concentrate on the more accessible oil in West Siberia.

In October 2002, the Nippon Oil Corporation imported a cargo of crude oil from Russia, part of moves by Japan to diversify its supply sources.

NOTABLE ENERGY DEVELOPMENTS

OUTLOOK

The government has approved the basic provisions of Russia's energy strategy for the period to 2020. Target values for the overall increase in energy consumption in Russia over the period will be 22 to 36 percent. By energy type, gas consumption should increase by 18 to 24 percent, consumption of petroleum products by 36 to 53 percent, coal use by 33 to 70 percent, and nuclear power generation by 40 to 60 percent. As a result, the gas share within primary energy will fall, notably in the electricity industry, overall from 64 percent to a range of 50 to 57 percent.

NATURAL GAS EXPORT

Exports of Russian gas to Europe in the first eight months of 2002 increased 4.5 percent year-on-year by 3.7 BCM to 85.1 BCM according to the Russian Energy Ministry. Russia and Turkmenistan have reached an intergovernmental agreement on natural gas supplies from Turkmenistan to Russia until 2020. Under this agreement, Russia is expected to buy 10 BCM of gas a year starting 2005, increasing to 20 BCM per year starting 2008.

OIL PRODUCTION AND EXPORT

Russia expects to produce 360-362 Mt of oil and to export 145 Mt of crude oil and 60 Mt of petroleum products in 2002, according to the Russian Energy Ministry. The Energy Ministry announced plans to trade Urals crude oil brand in the International Petroleum Exchange in London. Oil producers have suggested that this brand could become a standard marker crude.

POWER GENERATION

Gas accounted for 69.5 percent of all fuel supplied to power stations run by Unified Energy Systems, the national electricity monopoly, in the first seven months of 2002, compared with 64 percent in the same period of 2001. Fuel oil accounted for 4.2 percent of the supplies (5.8 percent), and coal 26.3 percent (30.2 percent).

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SINGAPORE

INTRODUCTION

Singapore is a small island nation located between Malaysia and Indonesia. The total area of the island is 682.7 square kilometres, and the population in 2000 was about 4 million. However, despite its small size and population, Singapore is one of the more highly industrialised and urbanised economies in the Southeast Asia region.

In 2000, real gross domestic product (GDP) was US$ 93.2 billion and per capita GDP was US$ 23,195 (both in 1995 US$ at PPP). Due to its strategic location on the Straits of Malacca, Singapore is an important shipping centre and has a large petroleum refining industry. Singapore has no indigenous energy resources and relies entirely on imports to meet its energy requirements.

Table 33 Key data and economic profile (2000)

Key data		Energy reserves	
Area (sq. km)	682.7*	Oil (Proven)	0
Population (million)	4.02	Gas	0
GDP Billion US$ (1995 US$ at PPP)	93.20	Coal (Recoverable)	0
GDP per capita (1995 US$ at PPP)	23,195		

Source: Energy Data and Modelling Center, IEEJ.

*Singapore Department of Statistics.

ENERGY DEMAND AND SUPPLY

PRIMARY ENERGY SUPPLY

Singapore is highly dependent on imported oil, which accounts for almost all primary energy supply. Most oil is used for power generation or as feedstock in refining and petrochemical industries. Natural gas plays a small role which is expected to expand in future years.

All electricity generation in Singapore is thermal, and most of it is from oil. Electricity demand grew an average of 7.3 percent per annum from 1990 to 2000 and is projected to grow 4 to 5 percent per annum from 2000 through 2010. The amount of electricity consumed in 2000 was 30,566 GWh. Manufacturing and service industries accounted for most of this consumption.

To meet growing demand for electricity, Tuas Power Ltd built the Tuas A power station in two stages. The first stage of the project, which has a combined capacity of 1,200 MW, began operation in 1999; its second 600 MW generating unit entered commercial service in January 2000. SembCorp Cogen Pte Ltd has developed a co-generation plant with a generating capacity of 650 MW, which came on line in 2001. In addition to building new power stations, Singapore is active in upgrading existing power stations with newer and bigger generating units.

FINAL ENERGY CONSUMPTION

In rough terms, the industrial and transport sectors each account for about two-fifths of final energy consumption in Singapore, while the residential and commercial sectors account for somewhat less than one-fifth. About three-quarters of final consumption is in the form of oil fuel, mostly for transport and industry, while about a quarter is in the form of electricity.

Table 34 Energy supply & consumption (2000)

Total Primary Energy Supply	(ktoe)	Total Final Energy Consumption	(ktoe)	Power Generation	(GWh)
Indigenous Production*	64	Industry Sector*	3,992	Total	30,566
Net Imports & Other	21,859	Transport Sector*	4,389	Thermal	30,566
TPES	21,923	Other Sectors	2,148	Hydro	0
Coal	0	TFEC	10,529	Nuclear	0
Oil	20,578	Coal	0	Others	0
Gas*	1,281	Oil*	7,900		
Others*	0	Gas	0		
		Electricity & Others	2,629		

Source: Energy Data and Modelling Center, IEEJ (see http://www.ieej.or.jp/apec/database/selecttable.html)
*Data obtained from International Energy Agency (IEA).

POLICY OVERVIEW

There are no energy subsidies in Singapore. Allowing energy prices to reflect international market prices for fuel ensures that energy is used efficiently. Electricity tariffs are reviewed periodically to ensure that they reflect true costs. Prices for other forms of energy, such as the piped gas supplied by PowerGas Ltd and petroleum products supplied by oil companies, are set by the individual private suppliers and reflect international market prices of fuel. Many reforms have been introduced to increase competition in the natural gas and electricity markets.

NATURAL GAS

The government is actively working to reduce Singapore's dependence on oil. Since January 1992, natural gas from Malaysia has been used for electricity generation as a first step towards energy supply diversification. Gas imports from Indonesia were introduced in 2001.

The gas industry has been restructured by separating the ownership of the gas transportation business, which is a natural monopoly, from the contestable functions of importing, trading and retailing. The gas distribution and transmission network will be owned by a gas grid company, PowerGas Ltd, which will allow players open and non-discriminatory access to the network.

ELECTRICITY

The vertically integrated electricity industry was restructured in 1995 to introduce competition in electricity generation and supply. Two generation companies (PowerSenoko Ltd and PowerSeraya Ltd), a transmission and distribution company (PowerGrid Ltd) and a supply company (Power Supply Ltd) were formed under Singapore Power Ltd. The third generation company, Tuas Power, took over the development and operation of the Tuas Power Station. The Public Utilities Board, which had been supplying power to the entire economy since 1963, was reorganised in October 1995 to take on a new role of regulating the power and piped gas industries.

The Singapore Electricity Pool (SEP), a wholesale electricity market, began operation on 1 April 1998. This pool facilitates the trade of wholesale electricity in a competitive environment. Generation companies compete to sell electricity through the Pool. Electricity suppliers then purchase electricity at competitive prices from the Pool for retail sale to consumers. As competition in electricity generation and supply develops, there will be less reliance on regulation.

In September 1999, the government of Singapore carried out a comprehensive review of the electricity industry. The review's key objective was to implement an electricity market structure and regulatory framework that would support a competitive electricity industry while maintaining the reliability and security of power supply. Based on the review, the government decided in March 2000 to further reform the industry and obtain the full benefits of competition. It decided to introduce wholesale competition in generation and retail competition for large industrial and commercial consumers, with retail choice for smaller customers to be introduced later. It decided as well to establish an independent system operator. PowerGrid remained subject to performance-based regulation since its transmission and distribution business is a natural monopoly.

In the restructured electricity industry, contestable functions like generation and retailing will be separated from non-contestable functions like transmission and distribution at the ownership level. To this end, Singapore Power divested two generation companies, PowerSenoko and PowerSeraya, to Temasek Holdings on 1 April 2001. On the same date, The Energy Market Authority of Singapore (EMA) was established to replace the PUB as the regulator of electricity and gas industries and to take on the system operator functions that had been performed by PowerGrid. The Energy Market Company Pte Ltd was formed as an EMA subsidiary to operate the SEP.

As of 1 July 2001, consumers with a maximum power requirement (contracted capacity) of 2 megawatts (MW) and above have been able to buy electricity from competitive retailers apart from Power Supply Ltd, Singapore Power's retail arm. The electricity retail market will be further liberalised to allow more consumers to choose the retailer from whom they buy electricity.

ENERGY DIVERSIFICATION, ENERGY EFFICIENCY AND CONSERVATION

To encourage the use of natural gas, owners of natural gas buses and passenger cars (including taxis) have been given rebates from October 2001. Such owners receive a rebate equivalent to 5 percent and 20 percent of the vehicle's open market value for buses and passenger cars (including taxis) respectively that can be used to offset the fees and taxes payable at registration. They also receive a road tax rebate of 20 percent. The rebates will be in place till after 31 December 2003 and reviewed for their relevance thereafter.

Upgrading of power stations with newer and bigger machines to generate electricity has improved Singapore's overall system thermal efficiency, which reached 38 percent in 2001. The five petroleum refineries also continually upgrade their operations with sophisticated value-added processes and employ stringent energy conservation practises.

Energy conservation has been actively promoted and pursued at a national level through a series of fiscal and non-fiscal policies with the objective of improving overall system efficiency through better load management. The EMA provides advisory services in efficient use of electricity to consumers in the industrial and commercial sectors. A set of energy conservation standards for building design has been incorporated into the building regulations administered by the Building and Construction Authority. A multi-agency committee is continuously looking into ways to increase energy efficiency and conservation in various areas, such as its land transport system.

A National Energy Efficiency Committee (NEEC) was set up in 2001 to promote energy conservation through the efficient use of energy in the industrial, building and transportation sectors and promote the use of cleaner energy sources such as natural gas and renewable energy sources. A labelling scheme that differentiates energy-efficient electrical appliances from less energy-efficient ones has been introduced to help consumers make better-informed choices. Examples of other programmes are energy-efficient building award scheme and energy audit scheme for large energy consumers.

NOTABLE ENERGY DEVELOPMENTS

ARRIVAL OF GAS IMPORTS FROM INDONESIA

In January 2001, after a 656-kilometre gas pipeline from Indonesia's West Natuna gas field to Singapore was completed, Singapore received its very first shipments of gas from Indonesia. Under the current contract, Indonesia's Pertamina is delivering 9.1 MCM of gas per day. Another contract with Pertamina, signed in 2000, will increase gas imports by an additional 9.8 MCM per day starting in 2003. Most of this imported gas is to be used for power generation. Singapore also imports gas from Malaysia.

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CHINESE TAIPEI

INTRODUCTION

Chinese Taipei is an isolated island off the southeast coast of China with an area of some 36,000 square kilometres and a population of 22 million. It is an important trading centre with one of the world's busiest ports, Kaohsiung. Its main industries are electronics and petrochemicals.

Chinese Taipei sustained high levels of economic growth, averaging 7.7 percent per year, between 1980 and 1995. The economy's growth rates slowed after the Asian financial crisis in 1997, but are still relatively strong compared with those of its neighbours. GDP per capita was US$ 15,321 in 2000 (in 1995 US$), and GDP was projected to grow by 3 percent for 2002.

Chinese Taipei has very limited domestic energy resources and relies on imports for most of its energy requirements. Oil reserves are less than 1 MCM and coal reserves are 1 Mt. Gas reserves are larger at around 77 BCM. In 2000, electricity generation capacity totalled 29,634 MW.

Table 35 Key data and economic profile (2000)

Key data		Energy reserves**	
Area (sq. km)	36,000	Oil (Proven)	0.636 MCM
Population (million)	22.22	Gas	76.5 BCM
GDP Billion US$ (1995 US$)*	340.38	Coal (Recoverable)	1.0 Mt
GDP per capita*	15,321		

Source: Energy Data and Modelling Centre, IEEJ.

*Purchasing power parity (PPP) figures not available.

**US EIA.

ENERGY DEMAND AND SUPPLY

PRIMARY ENERGY SUPPLY

Total primary energy supply in Chinese Taipei was 77,400 ktoe in 2000, of which 43 percent was provided by oil, 36 percent by coal, 14 percent by nuclear power and 7 percent by natural gas. Some 85 percent of energy needs were imported, including most of the natural gas and nearly all of the oil and coal.

Chinese Petroleum Corporation (CPC), the state oil company, is the dominant player at all stages of Chinese Taipei's petroleum industry, including exploration, importation, refining, storage, transportation, and marketing. The main supplier of crude oil to Chinese Taipei is the Middle East. In 1999, the domestic oil market was liberalised by freeing up import regulations for fuel oil, jet fuel, and LPG. Significant competition began in August 2000 when commercial production began at the economy's first private refinery, the facility in Mailiao owned by Formosa Petrochemical Corporation.

CPC also is responsible for domestic exploration, production and imports of natural gas. CPC operates Chinese Taipei's only liquefied natural gas (LNG) receiving terminal at Yungan, Kaohsiung. In anticipation of growing gas demand for power generation and in light of gas market liberalisation, the government has granted permits to import LNG to companies other than CPC and is accepting bids to build additional LNG terminals from both CPC and private firms. Chinese Taipei has imported LNG from Indonesia since 1990 and from Malaysia since 1995.

Almost all of Chinese Taipei's coal is imported, primarily from Australia and Indonesia. Coal is used for power generation as well as in the steel, cement and petrochemical industries.

In 2000, Chinese Taipei produced 184,853 GWh of electricity, of which 74 percent came from thermal power plants, 21 percent from nuclear plants, and 5 percent from hydropower plants. Taiwan Electric Power Company (Taipower), a state-owned utility, currently dominates the electricity sector, but the role of independent power producers (IPPs) has expanded rapidly since the wholesale electricity market was opened to competition in 1994.

Table 36 Energy supply & consumption (2000)

Total Primary Energy Supply	(ktoe)	Total Final Energy Consumption	(ktoe)	Power Generation	(GWh)
Indigenous Production	11,476	Industry Sector	26,134	Total	184,853
Net Imports & Other	65,924	Transport Sector	12,527	Thermal	137,480
TPES	77,400	Other Sectors	12,990	Hydro	8,870
Coal	27,493	TFEC	51,651	Nuclear	38,503
Oil	33,514	Coal	8,391	Others	0
Gas	5,596	Oil	28,000		
Others	10,797	Gas	1,490		
		Electricity & Others	13,770		

Source: Energy Data and Modelling Center, IEEJ (see http://www.ieej.or.jp/apec/database/selecttable.html)

FINAL ENERGY CONSUMPTION

Chinese Taipei's final energy consumption grew by 6.4 percent in 2000 to 51,651 ktoe. The industrial sector consumed 51 percent of energy used, the transportation sector 24 percent and other sectors 25 percent. Oil is the dominant fuel, accounting for 54 percent of energy consumption. Electricity accounted for 27 percent of energy use, coal for 16 percent and gas for just 3 percent.

POLICY OVERVIEW

The Energy Commission under the Ministry of Economic Affairs (MOEA) was established in November 1979 to formulate and implement national energy policy. It is charged with carrying out the Energy Management Law and the Electricity Law. It regulates natural gas utilities, petroleum and LPG filling stations, and the importation, exportation, production and sale of petroleum products. It maintains an energy database, evaluates energy demand and supply requirements, and promotes energy conservation. Further, it implements research and development programmes and promotes international energy cooperation.

The liberalisation and privatisation of energy-related enterprises has been promoted in recent years to let the private sector build power plants and oil refineries, promote transparency in domestic fuel prices and electricity rate adjustments, strengthen the management of energy supply and demand, and address energy-related environmental impacts. In electric power markets, wholesale competition was established in 1994, when independent power producers were allowed to invest in generating facilities and sell their output to Taipower, the integrated state electric utility. Retail competition and unbundling of Taipower's generating assets from its transmission and distribution assets are proposed in a new electricity law (see notable energy developments, below). Oil markets were fully opened to retail and wholesale competition in 2001.

NOTABLE ENERGY DEVELOPMENTS

OIL MARKET LIBERALISATION

Chinese Taipei's oil market was fully liberalised by the Petroleum Administrative Law that was promulgated on 11 October 2001 and became effective on 26 December 2001. The number of oil-related businesses, especially gasoline and diesel wholesalers, has been increasing dramatically. By the end of August 2002, 103 certificates had been issued to gasoline and diesel wholesalers and 10 companies had registered as oil exporters. In the oil importing business, the Chinese Petroleum Corporation has been joined by Formosa PetroChemical Company, Lee Chang Yung Chemical Industry Corporation, Ming-Xing Enterprises, Esso Petroleum Taiwan and Caltima Corporation. In oil refining, the Chinese Petroleum Corporation and Formosa PetroChemical Company will soon be joined by Ho Tung Chemical Corporation which has obtained a permit to build a refinery in Taichung.

A TURNING POINT FOR THE NATURAL GAS INDUSTRY

Chinese Taipei has limited natural gas production capacities and has been importing LNG since 1990. Since then, the total consumption of natural gas has increased significantly, from 1.8 BCM in 1990 to 6.9 BCM in 2001. The use of gas for electricity generation has grown especially fast, now comprising two-thirds of total gas consumption. The key role of power sector demand in the gas market is expected to continue, as the government is considering a policy to approve construction only of LNG power plants and to increase the share of LNG in electricity generation to one-third by 2010. Due to gas market growth and liberalisation, private companies are expected to enter the upstream gas importation and wholesale businesses in the foreseeable future. Therefore, the government is preparing relevant regulations to include in a new Natural Gas Business Law.

LIBERALISATION OF THE ELECTRIC POWER INDUSTRY

The Chinese Taipei government is considering a new electricity law to make the power industry more efficient and competitive. Key features of the proposed law are as follows:

- Taipower would be privatised, and its monopoly on generation would be removed. Transmission and distribution facilities would continue to be owned by Taipower and regulated as natural monopolies. (Taipower was to be privatised in 2001, but the timing is now uncertain due to delays in passage of enabling legislation.)
- Electric utilities would include integrated utilities with generation, transmission and distribution assets, as well as utilities with transmission and distribution assets only. Utilities would have an obligation to supply power, and their electricity tariffs would be regulated to control monopoly power.
- Power generation companies could offer electricity at wholesale to any utility or sell directly to customers at retail. They would provide electricity through their own transmission lines or through a grid dispatched by the Independent System Operator (ISO). Their electricity tariffs would not be regulated.
- Gradually, consumers would be allowed to purchase electricity from any supplier.

NEW IPPS BEGIN COMMERCIAL OPERATION

By late 2002, the amount of electric generating capacity provided by independent power producers in Chinese Taipei had reached 4,600 MW. In the north, the Hualian Ho-Ping power plant (2x650 MW) and Hsintao power plant (600 MW) began service in 2002, following the Ever plant (2x450 MW), for total IPP capacity of 2,800 MW. In the central region, the Mailiao plant (3x600 MW) provides another 1,800 MW of IPP power. The new IPP capacity in the north has relieved south-to-north transmission constraints. The peak load of the north was projected to be about 12,540 MW in 2002, while Taipower's net peak supply capacity was 7,440 MW, for a net supply gap of 5,100 MW in the north without IPPs. With 2,800 MW of new IPP capacity in the north, the amount of electricity required from the south has been reduced by more than half to just 2,300 MW, making electricity supply in the north much more reliable during the summer peak demand period. Another four IPP plants, with a total capacity of 2,910 MW, should enter service in 2003 and 2004.

TRANSMISSION AND SUBSTATION PROJECTS

Taipower has been steadily building new transmission capacity to help meet growing electricity demand. Its Fifth Transmission and Substation Project, which was started in July 1996 and completed in June 2001, installed 30,248 MVA of transmissions substations and 2,215 km of transmission lines. Its Sixth Transmission and Substation Project, which runs from July 2001 through December 2006, will install 64,495 MVA of substations and 3,660 km of transmission lines. In 2001 alone, Taipower completed 8,510 MVA of substation and 544 km of transmission lines, of which 350 km are overhead lines and 194 km underground cables.

FOURTH NUCLEAR POWER PLANT

In September 2000, the MOEA proposed a halt to construction of the 2,700 MW Number 4 Nuclear Power Plant at Kungliao, in response to the findings of a committee it had established. The Administrative Yuan announced a halt to construction in October, but the Legislative Yuan did not agree with this action. The dispute was sent to the Judicial Yuan, which ruled on constitutional aspects in February 2001. The Legislative and Administrative Yuans then agreed to re-instate the project's budget, and construction resumed on 14 February. By the end of 2001, the plant was 36 percent complete. The plant's two units are scheduled for completion by July 2006 and July 2007, respectively.

NEW AND RENEWABLE ENERGY

To achieve a goal of 3 percent of total energy consumption from renewable sources by 2020, aggressive renewable programmes were begun in Chinese Taipei in 2000. Consumers can receive a subsidy for installing solar heaters. Users of photovoltaic and wind turbines can receive a down payment subsidy of up to 50 percent. Geothermal rights have been deregulated to encourage private investment. Between 2000 and 2004, 800,000 square metres of solar heating panels, 18 MW of wind power, 7 MW of photovoltaic power, and 10 MW of geothermal power are expected to be put into operation. These programmes will lay a good foundation for the development of renewable energy in Chinese Taipei, which is seen by the government as enhancing energy security, environmental protection and economic development. Looking forward, a renewable energy development bill to provide enhanced incentives for investment in renewable technologies has been prepared by the Administrative Yuan and delivered to the Legislative Yuan.

Chinese Taipei has completed a wind energy potential map for businesses interested in wind power facilities. Four wind power generator sets, with a capacity of 600 kW each, have been built by Taipower at Chungtung in Penghu County to reduce the need for expensive diesel fuel in thermal power plants. Another four sets, with a capacity of 660 kW each, are located at the Mailiao Power Station of the Formosa PetroChemical Company. Many other companies, including foreign ones, are currently proposing new wind power projects to the Energy Commission.

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THAILAND

INTRODUCTION

Thailand is located in southeast Asia and shares borders with Malaysia to the south and Myanmar, Laos and Cambodia to the north. It has an area of 513,115 square kilometres and a population of about 60.7 million at the end of 2000. In 2000, GDP was about US$ 373 billion (at US$ 1995 at PPP), an increase of 4.3 percent over 1999.

Over the past two decades, with the impetus of strong economic growth that was temporarily interrupted by the 1997-98 financial crisis, Thailand has not only significantly increased its energy consumption but has also sufficiently developed its energy sector that import dependency has steadily declined. In 2000, net energy imports accounted for 55 percent of energy supply in the economy; down significantly from 96 percent in 1980.

In 1997, an economic recession due to the Asian financial crisis caused GDP and energy demand to decline for the first time in 30 years. Two of the effects of the crisis were depreciation of the currency and higher inflation, which weakened domestic purchasing power by making imported energy such as oil more expensive. But by the second half of 1999, economic counter-measures by the government began to take effect. Currency levels stabilised and the inflation rate declined. A gradual recovery, particularly in the industrial export sector, has since taken hold.

Table 37 Key data and economic profile (2000)

Key data		Energy reserves*	
Area (sq. km)	513,115	Oil (Proven)	43 MCM
Population (million)	60.73	Condensate (Proven)	39 MCM
GDP Billion US$ (1995 US$ at PPP)	373.14	Gas (Proven)	360 BCM
GDP per capita (1995 US$ at PPP)	6,144	Coal (Recoverable)	1,373 Mt (Lignite)

Source: Energy Data and Modelling Centre, IEEJ.

*Department of Mineral Fuels, Ministry of Energy.

ENERGY DEMAND AND SUPPLY

PRIMARY ENERGY SUPPLY

In 2000, Thailand's primary energy supply was 63,255 ktoe. Oil comprised 55.4 percent of primary supply, gas 31 percent, coal 12.4 percent and others 1.2 percent. The supply of oil and coal was slightly down compared to 1999, and the 3.8 percent increase in primary energy supply was almost entirely due to a 16.5 percent increase in gas supply.

Energy imports accounted for 54.9 percent of primary energy supply in 2000, a slightly lower share than in 1999, continuing the general downward trend in energy import dependency of recent years. But Thailand imported 92 percent of its oil requirements in 2000, and a high level of oil import dependency is expected to continue in the foreseeable future.

Thailand's major source of crude oil is the Middle East, though oil is also imported from ASEAN economies, the Asia-Pacific, and North America. At the end of 2000, Thailand's total proven reserves of crude oil were around 43 MCM. Onshore reserves are located in the Sirikit field (14.3 MCM) while offshore reserves (28.9 MCM) are mainly in the Benchamas, Jarmjuree, and Kung fields. For condensate, total proven reserves are 39 MCM. All deposits are located offshore with major pools in the Erawan, Pailin, Bongkot and JDA areas.

Due to the lingering effects of the financial crisis and high oil prices, domestic petroleum product consumption in 2000 was lower than might otherwise have been the case, meaning that domestic refineries were not required to operate at full capacity. Capacity utilisation in 2000 was around 86 percent. To mitigate losses, Thai refineries were exported some of their output. Exports of petroleum products were 2,101 ktoe in 2000. Thailand has a combined refinery capacity of 817,000 barrels per day.

Thailand is more self-sufficient with respect to natural gas. Imports, from Myanmar, are around 20 percent of demand. Gas production was around 6 percent higher in 2000 compared with 1999. Natural gas is used largely for electricity generation.

Coal in Thailand is used for electricity generation and in the industrial sector. Most of Thailand's proven coal reserves are lignite, coal of low calorific value. The total volume of recoverable reserves is 1,373 Mt, most of which is located in the Mae Moh basin. Around a third of the economy's coal requirements are imported.

Thailand's electricity generation in 2000 was 95,977 GWh, 8.1 percent more than in 1999. Almost all domestic generation (96 percent) was thermal. The remaining 4 percent was supplied by hydro, geothermal, solar and wind turbine energy. Natural gas is the most important thermal fuel source for electricity generation, accounting for around 60 percent of thermal consumption. Other important thermal fuels were fuel oil and lignite coal. To supplement domestic production and balance peak loads, Thailand imports electricity from the Lao Peoples Democratic Republic. Imports are typically 1 to 2 percent of requirements.

Table 38 Energy supply & consumption (2000)

Total Primary Energy Supply	**(ktoe)**	**Total Final Energy Consumption**	**(ktoe)**	**Power Generation**	**(GWh)**
Indigenous Production	28,559	Industry Sector	12,833	Total	95,977
Net Imports & Other	34,696	Transport Sector	18,828	Thermal	89,949
TPES	63,255	Other Sectors	9,897	Hydro	6,026
Coal	7,838	TFEC	41,557	Nuclear	0
Oil	35,039	Coal	3,660	Others	2
Gas	19,620	Oil	28,947		
Others	758	Gas	1,389		
		Electricity & Others	7,562		

Source: Energy Data and Modelling Center, IEEJ (see http://www.ieej.or.jp/apec/database/selecttable.html)

FINAL ENERGY CONSUMPTION

Thailand's total final energy consumption for 2000 was 41,557 ktoe, an increase of 2.2 percent over the previous year. Petroleum products account for the highest proportion of secondary demand (70 percent), followed by electricity (18 percent), lignite coal (9 percent) and gas (3 percent). Demand for natural gas and electricity increased by 23 and 8 percent respectively from 1999. On the other hand, petroleum demand grew by only 1 percent. High oil prices since 1999 have pushed up end-use petroleum prices; as a result, residential and certain commercial and industrial sub-sectors have reduced their consumption.

The transportation sector was the largest energy consuming sector and accounted for 45 percent of total final energy consumption. This was a lower share than the 47 percent in 1999 and at 18,828 ktoe was almost 2 percent less than consumption in 1999. The industry sector consumed

12,347 ktoe in 2000, an increase of 3 percent from the previous year. Energy consumption in the residential and commercial sectors increased by 9.5 percent over 1999.

Electricity demand is estimated to have increased by 8 percent between 1999 and 2000. Although hydro generation was around 70 percent higher in 2000 than in 1999, Thailand still depended on fossil fuels for around 95 percent of generation.

POLICY OVERVIEW

DEREGULATION, PRIVATISATION AND RESTRUCTURING

Thailand has been deregulating its energy sector for around a decade with a primary objective of creating a more competitive energy market. The oil and gas industries, both upstream and downstream, were completely de-regulated and liberalised in 1996. Deregulation of the electricity and gas sectors is less advanced although significant progress is being made in both.

ENVIRONMENT

Current energy policies in Thailand also focus on conservation and environment. A range of policies have been implemented or being considered to mitigate the environmental effects of energy production and use. Policy measures include the substitution of natural gas for coal and fuel oil in electricity generation, increasing the use of renewable electricity technologies, promoting clean coal technologies, implementing higher emissions standards for power plants (for example, SO_2 emissions have been reduced by more than 75 percent since 1996), and implementing emissions controls and higher fuel quality for motor vehicles.

ENERGY SECURITY

As a significant energy importer, especially of oil, Thailand is concerned about energy security. This concern applies to both the security of supply and volatile oil prices. To insulate the economy from oil supply and price shocks it is considering several different strategies. On the demand side, the government is promoting energy conservation and the efficient use of energy. It also advocates diversifying energy use away from oil towards less volatile energy markets such as natural gas, orimulsion, coal and renewable sources. Recognising the importance of emergency preparedness in the case of an oil shortage or crisis, Thailand is also considering establishing strategic oil stockpiles. The National Energy Policy Office (NEPO) is studying the national oil stockpiling strategy and is considering stockpiling options for Thailand. In addition, NEPO closely cooperates with other ASEAN economies to improve the ASEAN Petroleum Security Agreement (APSA) and to strengthen energy security in Asia.

NOTABLE ENERGY DEVELOPMENTS

OIL AND GAS

The Government-owned and vertically integrated oil and gas concern, the Petroleum Authority of Thailand (PTT), was partially privatised via a sharemarket float of 32 percent of its capital in December 2001. Since the de-control of oil prices in 1991, a large number of competitors, ranging from refiners to retailers, have entered the market. However, PTT still has the largest market share.

The LPG market was partially deregulated from November 2001, with full deregulation planned for 2003. LPG remains the dominant fuel for cooking.

Competition in the gas supply industry is now allowed for the direct purchase and sale of new gas supplies. Third party access to transmission and distribution pipelines is allowed in the case of new pipelines and where excess capacity is available on existing pipelines. Currently, PTT is the only operator in the gas pipeline business. An independent gas regulatory agency is to be established in 2006.

ELECTRICITY

Thailand is attempting to improve the efficiency of its electricity market through reforms to promote competition. Begun in 2000, power market reforms are to be completed by 2004 with deregulation of generation and retail supply. During 2003-2004, three state-owned enterprises, the Electricity Generation Authority of Thailand (EGAT), the Metropolitan Electricity Authority (MEA) and the Provincial Electricity Authority (PEA), will be privatised in the same way as PTT. A regulatory authority will be established, and a power pool will be set up. Consumers will be able to choose among competing suppliers.

As part of Thailand's Energy Conservation Program, a budget of 2,060 million Baht has been allocated from the government's Energy Conservation Promotion Fund to subsidise around 300 MW of renewable generation by small power producers (SPP). In July 2001, NEPO requested proposals and duly received 43 proposals amounting to around 775 MW and requesting some 6,000 million Baht of subsidies. Earlier in 2002, 17 SPPs, with a total proposed capacity of 313 MW had their proposals accepted.

ENERGY CONSERVATION

In 2000, under the newly elected government, Thailand declared "energy conservation" a crucial component of energy policy. The policy aims to achieve sustainable development, that is, to promote the efficient use of energy without depleting domestic natural resources or harming the environment. Efforts are also being made to reduce dependence on foreign energy sources.

With a view to decreasing the growth of energy consumption in the 2002-2011 period, the Strategic Plan for Energy Conservation was developed and approved by the National Energy Policy Council in April 2002. The four main prongs of the strategy are energy conservation, renewable energy utilisation, human resources development and public awareness campaigns. Targets for energy savings have been established for 2006 and 2011.

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UNITED STATES

INTRODUCTION

The United States (US) is the world's largest and most influential economy, with a GDP of US$ 9.2 trillion (in 1995 US$ at PPP) in 2000. The US is located in North America between Canada and Mexico. It has some 281 million people (2000), and spans 9.3 million square kilometres.

The United States enjoyed a lengthy economic expansion from 1991 through 2000. Growth was particularly robust from 1995 to 2000, averaging 3.8 percent per annum. But economic recession starting in early 2001 meant much slower growth of 0.3 percent that year (compared with 3.8 percent in 2000). Inflation fell from 3.4 percent in 2000 to 2.8 percent in 2001. Unemployment increased from 4.0 percent at the end of 2000 to 5.6 percent at the end of 2001 and 5.9 percent in mid-2002. The slowdown in the US economy, the world's largest in both size and net imports, acted as a drag on growth in other economies as well. But signs of economic recovery appeared during 2002.

The United States is by far the world's largest producer, consumer, and importer of energy. It is endowed with great energy resource wealth. At the end of 2001, there were 3,569 MCM of proven oil reserves and 5,195 BCM of proven dry natural gas reserves, as well as 1,271 MCM of gas liquids reserves. Recoverable coal reserves amount to some 249.6 billion tons. Electricity generating capacity in 2000 was 812 GW, of which 74 percent was owned by utilities and 26 percent by non-utility generators. But due to a large and wealthy population and extensive industrial base, the economy consumed 5.9 toe (FEC) per capita in 2000, nearly four times the APEC average and far in excess of production.

Table 39 Key data and economic profile (2000)

Key data		Energy reserves*	
Area (sq. km)	9,372,610*	Oil (Proven)	3,569 MCM**
Population (million)	281.55	Gas	5,195 BCM**
GDP Billion US$ (1995 US$ at PPP)	9,194	Coal (Recoverable)	249.6 Bt***
GDP per capita (1995 US$ at PPP)	32,655		

Source: Energy Data and Modelling Center, IEEJ.
*US Energy Information Administration.
**Oil and gas reserves as of 31 December 2001.
***Coal reserves as of January 1, 1997.

ENERGY DEMAND AND SUPPLY

PRIMARY ENERGY SUPPLY

In 2000, net primary energy supply in the United States was about 2,324 Mtoe. Broken down by fuel type: 39 percent was crude oil and petroleum products, 23 percent was coal, 24 percent was natural gas and 9 percent was nuclear. The remaining 5 percent of primary energy came from hydro, geothermal and other fuels. The United States imported about 26 percent of its energy requirements in 2000.

During 2000, the United States used about 919 Mtoe of crude oil and equivalent. Though petroleum product supply grew 1.5 percent per annum during the 1990s, domestic crude oil production levels declined by 2.3 percent per year as oil exploration and production companies turned their attention to cheaper, less mature basins in Africa, Asia and the Middle East. While 47 percent of oil demand was met by imports in 1990, the import share had climbed to 59 percent by 2001. Almost half of imported oil comes from OPEC economies. Neighbouring Canada and Mexico are the largest non-OPEC suppliers. Growth in the transportation and industrial sectors has been driving demand for petroleum products. Louisiana is the leading oil producing state in the United States, followed by Texas, Alaska and California.

The United States has about 3.2 percent of the world's natural gas reserves. Primary natural gas supply totalled 543 Mtoe in 2000, exceeding domestic production by 23 percent. Most of the production shortfall was met by imports from Canada through an extensive network of pipelines. Since the mid-1990s, there has been a surge in trans-border and interstate pipeline capacity to meet rapidly growing gas demand. The Alliance Pipeline from western Canada to the Chicago area began service in December 2000 with a capacity of 1.3 Bcf/day. Several other pipeline projects are being considered or are under construction, as are a range of domestic exploration and LNG projects. Gas use by industry and power generators has grown because gas is a clean fuel that makes environmental approvals easy, while most of the period since deregulation of wellhead gas prices in the 1980s has seen falling gas prices as an expanding pipeline network has made gas more widely available.

Natural gas prices spiked during the winter of 2000-2001, with average wellhead prices nearly triple those of the previous winter, but prices later subsided. The price spikes were largely due to strong demand in the power sector, where most new generating capacity in recent years has been gas-fired, as well as declining production in the late 1990s, high heating demand and temporarily low levels of gas in storage. The subsequent decline in prices, with spot prices at the Henry Hub reference point falling by August 2001 to half the winter's levels, can be attributed to faltering demand in the industrial sector, increased production in response to higher prices, and more normal storage levels. Prices began moving up again in early 2002, climbing about 40 percent from the lows of late 2001.

Table 40 Energy supply & consumption (2000)

Total Primary Energy Supply*	(ktoe)	Total Final Energy Consumption	(ktoe)	Power Generation	(GWh)
Indigenous Production	1,660,128	Industry Sector	574,289	Total*	3,802,463
Net Imports & Other	666,960	Transport Sector	615,085	Thermal	2,688,886
TPES	2,327,088	Other Sectors	461,117	Hydro*	275,600
Coal	540,565	TFEC	1,650,490	Nuclear	753,893
Oil	922,682	Coal	33,318	Others	84,084
Gas	545,273	Oil	862,056		
Others	318,568	Gas	377,353		
		Electricity & Others	377,764		

Source: Energy Data and Modelling Center, IEEJ (see http://www.ieej.or.jp/apec/database/selecttable.html)

*Figures differ somewhat from those in *APEC Energy Statistics 2000* as they incorporate recent revisions to official data contained in the US Energy Information Administration's *Annual Energy Review 2001*.

Coal use in the United States totalled 541 Mtoe in 2000. US coal reserves are concentrated in Appalachia and west of the Mississippi. Appalachian coal, which accounted for 38 percent of production in 2001, is mainly higher-sulphur coal from underground mines. Western coal, which accounted for most other production, is mainly low-sulphur coal from surface mines. Western coal production, which first surpassed that of Appalachian coal in 1998, was given a major boost by the Clean Air Act Amendments of 1990, which have required reduced sulphur emissions from coal combustion since 1995. During 2001, production increased in both regions but more in the West.

The United States is the fifth largest coal exporter in the world behind Australia, South Africa Indonesia and China. But US coal exports have fallen sharply since 1995, mainly because of lower world coal prices, increased competition from other coal-producing economies, and competition from natural gas for electricity production in export markets like Europe. In 2001, US coal exports fell to their lowest level since 1978, as a strong dollar made coal from competing nations cheaper and high spot prices on the domestic coal market made it more attractive for producers to sell at home. Three-quarters of the year's decline in exports was experienced by metallurgical coal, for which export markets have been shrinking in recent years with the penetration of advanced steel-making technologies that require less high-grade coking coal. The decline continued in the first half of 2002. Given world coal demand trends, US coal exports appear likely to decline further in the future.

The United States produced 3.8 million GWh of electricity in 2000 with 52 percent coming from coal, 20 percent from nuclear power, 16 percent from natural gas, 7 percent from hydropower, 3 percent from oil, and 2 percent from non-hydro renewable sources like wind and wood. Electricity prices fell every year between 1993 and 1999 but rose to 6.68 cents per kWh in 2000 and 7.16 cents per kWh in 2001, mainly because of higher natural gas prices.

The United States generates more nuclear power than any other country in the world but has not had any new nuclear power plants built since 1977. The Three Mile Island accident in 1979 raised concerns about nuclear power plant safety while ad-hoc regulatory responses to these concerns made some new plants very expensive; both factors deterred further expansion. However, the average utilisation rate of existing nuclear plants has risen steadily to 88 percent in 2001. Moreover, many nuclear plants have applied to the Nuclear Regulatory Commission (NRC) for 20-year extensions of their operating licenses, to 60 years. As of October 2002, the NRC had approved license extensions for 10 nuclear units and had applications for another 16 extensions under review, while 27 further units were expected to seek extensions over the next 5 years. Progress has also been made toward establishment of a permanent repository for nuclear waste (see notable energy developments below).

FINAL ENERGY CONSUMPTION

In 2000, end use energy consumption in the United States totalled 1,650 Mtoe. Broken down by sector, transport consumed 37 percent, industry accounted for 35 percent, and residential and commercial buildings used 28 percent. By fuel source, petroleum products accounted for 52 percent of consumption, natural gas for 23 percent and electricity for 19 percent. Coal and coke products made up 2 percent of consumption, and other fuels were responsible for the remaining 4 percent.

POLICY OVERVIEW

Energy policy in the United States is very supportive of market mechanisms. The Department of Energy (DOE) is responsible for developing and implementing energy policies and programmes, maintaining energy security, and supporting research and development of new energy technologies. The Federal Energy Regulatory Commission (FERC) and state public utility commissions share responsibility for regulating gas and electricity markets and promoting competition in those markets.

STRATEGIC PETROLEUM RESERVE

The United States imports more than half of its oil requirements, and its heavy dependence on oil imports is expected to continue. A vital policy instrument in this context is the Strategic Petroleum Reserve (SPR), established in 1977 in response to the oil crisis of the early 1970s. With a capacity of 700 million barrels and a current stock of some 580 million barrels, the SPR is the largest emergency oil stockpile in the world. Crude oil is stored mainly in four underground salt caverns near the Gulf Coast in Texas and Louisiana, and a distribution system is in place for the oil's use. DOE manages the SPR facilities and conducts test sales and releases from them. The current SPR inventory could replace roughly 52 days of imports, down from a peak of 115 days in 1985. Public and private oil inventories combined could replace about 150 days of imports, which substantially exceeds the International Energy Agency's requirement of 90 days.

The SPR represents a total investment of about US$ 20 billion with an annual requirement of US$ 158 million for maintenance and operation. The average price paid for oil in the reserve is approximately US$ 27 per barrel. Upon an order by the President, oil can be delivered to the US market within 15 days at a maximum rate of 4.1 million barrels per day. In the late 1990s, the SPR was upgraded to ensure its full and safe operation until at least 2025.

In 1991, due to supply and price concerns surrounding the Persian Gulf War, the US withdrew SPR oil for the first time in a non-test scenario. A total of 17.3 million barrels were released through competitive sales to private oil companies, less than initially authorised. In September and October 2000, 2.6 million barrels of oil were withdrawn from the SPR to pay for the 2.0 million barrel Northeast Home Heating Oil Reserve (NHHOR). This new reserve was established to avoid supply disruptions and price spikes such as those that occurred in late 1996 and early 2000. In March 2001, DOE formally established the NHHOR as a separate legal entity from the SPR. This reserve serves nine states in the Northeast that are heavily dependent on oil for home heating.

US ENERGY SANCTIONS

The United States has energy sanctions in place against Iran, Iraq, and Libya. Iran and Libya are affected by the Iran-Libya Sanctions Act (ILSA) of 1996, which imposes mandatory and discretionary sanctions on non-US companies that invest more than US $20 million annually in the Iranian oil and gas sectors. In early 1995, President Clinton signed two Executive Orders that prohibited US companies and their foreign subsidiaries from conducting business with Iran. The Orders also banned any "contract for the financing of the development of petroleum resources located in Iran." In March 2001, citing threats posed by Iran to US national security, President Bush extended these orders for six months, and in August 2001, he signed a bill to keep the sanctions for five more years.

Many foreign governments are opposed to the ILSA. The European Union passed a resolution in 1996 directing its members not to comply with the sanctions. In 1998, the EU and US reached agreement on a package of measures to resolve the ILSA dispute, but full implementation will require congressional approval. While no firms have been prosecuted under the ILSA, several have chosen to abandon projects in Iran due to the law. The US waived the Act's requirements for a joint venture by France, Russia and Malaysia to develop a gas field in southern Iran.

TECHNOLOGIES AND POLICIES TO LIMIT ENVIRONMENTAL IMPACTS

The United States has made substantial progress in reducing the environmental impacts of energy use. In particular, sulphur dioxide and nitrogen oxide emissions from coal plants have been cut dramatically through a combination of plant-specific requirements for emissions limits and a system of emissions trading. The acid rain programme established by the Clean Air Act Amendments of 1990 is expected to reduce yearly SO_2 emissions by 10 million tons or about half from 1980 levels by 2010. Phase II of the programme began in 2000, setting a nationwide cap of 9.2 Mt through 2009 and 8.95 Mt thereafter for all power plants with a capacity of 25 MW or greater and all new utility-owned plants. A trading system for SO_2 emissions permits, in place since 1995, has reduced emissions to 29 percent below legally required levels and has limited the cost of reducing emissions to about US$ 200 per ton. Since 1970, despite a doubling of coal use, aggregate emissions of key air pollutants (SO_2, nitrogen oxides, mercury, carbon monoxide and volatile organic compounds) have declined by 31 percent.

With the objective of extending this progress, the Bush Administration announced in 2002 a set of objectives for further reducing emissions of sulphur dioxide, nitrogen oxides, and mercury. Annual SO_2 emissions would decline from 11 million tons in 2000 to 4.5 million tons by 2008 and

3.0 million tons by 2018. Yearly NOx emissions would decline from 5 million tons in 2000 to 2.1 million tons by 2008 and 1.7 million tons by 2018. Otherwise put, NOx and SOx emissions would be cut roughly in half by 2010 and by two-thirds by 2018 from current levels. In addition, it was proposed to reduce the carbon intensity of the economy, or ratio of carbon emissions to GDP, by 18 percent by 2012.

CLEAN COAL TECHNOLOGY

Since the United States obtains over half of its electricity from coal, major emphasis has been placed on the development of technologies for limiting environmental emissions from coal-fired power plants. The NEP proposed continued development of clean coal technology through US$2 billion in R&D funding over a next ten-year period and permanent extension of an existing R&D tax credit. Until fairly recently, the main focus has been on reducing traditional air pollutants, namely particulates, SOx, and NOx. But the focus has been shifting to development of carbon sequestration technologies, including plans for a coal gasification combined cycle plant that separates carbon and hydrogen streams from the coal so that all the carbon is sequestered and atmospheric emissions of carbon are nil. If the concept can be demonstrated and the costs are not too high, it could point the way to a hydrogen economy based in part on abundant fossil fuels which could be a key means of limiting atmospheric concentrations of carbon dioxide over the longer term.

NUCLEAR POWER TECHNOLOGY

Nearly one-fifth of electricity in the United States is generated by nuclear power, from which atmospheric pollution and carbon dioxide emissions are close to zero. The US is an active participant, along with Japan and others, in development of Generation IV technologies with enhanced passive safety features and more standardised designs to limit costs. These hold the promise of retaining nuclear power as a major option after the current generation of plants is retired.

RENEWABLE ENERGY TECHNOLOGY

"New" renewable energy sources (other than hydropower) have continued to make inroads from a small base. The trend has been encouraged by a tax credit of 1.2 cents per kilowatt-hour, in 1992 dollars, escalating with inflation to 1.8 cents per kWh currently, for the first ten years of electricity production from new wind and closed-loop biomass. The credit was established by the Energy Policy Act of 1992, briefly lapsed for new facilities after 1999, and was later extended through 2001 and then through 2003; a further extension through 2006 was being considered by Congress in 2002. Wind power capacity additions, after subsiding from about 600 MW in 1999 to some 50 MW in 2000, rebounded sharply to a record of more than 1,700 MW in 2001, bringing total installed wind capacity to more than 4.2 GW. The Wind Powering America initiative at the Department of Energy has set an ambitious goal of having 80 GW of wind turbines in place by 2020.

Other renewable technologies have received substantial attention as well. The photovoltaic systems programme aims, by 2004, to increase PV thin-film efficiencies from 7 percent up to 12 percent, to cut module costs by half to US$ 1.25 per peak watt, to validate a lifetime of 25 years or greater for PV systems, and to reach 1 GW of cumulative sales by US firms. By 2020, it is anticipated that cumulative PV sales could grow to 30 GW. The geothermal programme at DOE aims to reduce costs of geothermal power from 5 to 8 cents per kWh in 2000 to a range of 3 to 5 cents per kWh by 2007. DOE's bio-power programme aims to increase generating capacity from energy crops, agricultural residues, wood and wood residues from 3 GW in 2000 to 10 GW by 2010, while its biofuels programme aims at 2.2 billion gallons of cellulosic ethanol production by 2010, versus zero in 2000. Renewables R&D gets about US$ 250 million in government funding each year.

Several states have implemented renewable energy portfolio standards, the largest to date being Texas, Minnesota, and Iowa; and such a standard is being considered for the US as a whole in comprehensive energy legislation before the Congress. The Energy Information Administration has estimated that a 20 percent renewable energy portfolio standard for the year 2020 would, if implemented through a system of tradable credits, yield a market value for credits on the order of 5 cents per kilowatt-hour. While that would imply a first-order price increase of 1 cent per kWh (5 cents per kWh applied to 20 percent of the generating mix), the EIA found that consequent easing of natural gas demand would limit the net effect on electricity prices, after considering reduced costs of gas input to power production, of just 0.4 cents per kWh, or about 5 percent of the average electricity price.

ENERGY CONSERVATION STANDARDS

TRANSPORTATION STANDARDS

Corporate Average Fuel Efficiency (CAFE) standards, in place since 1978, require that light trucks and automobiles sold by each vehicle manufacturer attain a certain average level of fuel economy, with sales in excess of this standard subject to fines. Historically, CAFE standards helped to bring about and sustain a huge improvement in the efficiency of the vehicle fleet, despite relatively low gasoline prices. But the fuel economy standard has been static at 27.5 miles per gallon for cars since 1985 and 20.7 miles per gallon for light trucks since 1996. Due to increased sales of sport utility vehicles and minivans, which fall within the light truck category, average fleet efficiencies have even declined slightly in recent years, reaching a 20-year low of 23.8 mpg by 1999. In considering comprehensive energy legislation during 2001, the Congress rejected a legislative mandate for more stringent CAFE standards. However, a six-year-long statutory prohibition on examination of fuel efficiency standards by the Department of Transportation (DOT) was lifted in December 2001. DOT is reviewing CAFE standards for 2005-10 model years and may raise them.

In addition to fuel economy standards, several other policies are proposed or in place to raise the efficiency and limit the environmental impacts of transport. The Department of Energy has invested heavily over the last decade, along with major US automakers, in the Partnership for the Next Generation of Vehicles and the Freedom CAR initiative, which support research and development of gasoline hybrid and fuel cell vehicles that could ultimately triple the efficiency of vehicles on the road. The DOE budget for this and other transportation R&D is around US$ 250 million per annum.

To help deploy more efficient technologies on the road, the National Energy Plan (NEP) recommended a tax credit for fuel-efficient vehicles, as well as an efficiency-based income tax credit for purchase of new hybrid and fuel cell vehicles between 2002 and 2007. The NEP also recommended support for buses powered by fuel cells and clean fuels, as well as promotion of Intelligent Transportation Systems (ITS) like traveller information/navigation systems, freeway management, and electronic toll collection to reduce the traffic congestion that leads to a major share of pollution from automobiles.

BUILDING AND APPLIANCE STANDARDS

The Department of Energy has energy efficiency standards in place for all major types of energy-using appliances, including air conditioners, clothes washers and dryers, space and water heaters, kitchen ranges and ovens, refrigerators and freezers, and lighting. In 2001, new minimum efficiency standards were issued for central air conditioners and heat pumps, water heaters, clothes washers, and some types of commercial heating and cooling equipment. The National Energy Plan called for appliance standards to be strengthened for products already covered and extended to additional products where technologically feasible and economically justified.

The highly successful Energy Star labelling programme clearly signals high efficiency in office buildings and appliances to consumers. The NEP recommended that the program be expanded from office buildings to include schools, stores, homes, and health care facilities. It also recommended that Energy Star labels be extended to additional products, appliances, and services. Further, the NEP recommended doubling expenditure on weatherisation of houses for low-income households, as well as support for educational programs related to energy development and use.

ELECTRICITY MARKET REFORM

The United States has achieved a high degree of competition in its electric power markets. Roughly one-third of all power generated in the United States in 2002 was provided by independent, non-utility generators. Seventeen states, with nearly half the US population, allow consumers to choose their electricity supplier. Virtually all new electric generating capacity which is planned or under construction is being financed and built by independent power producers; almost no new capacity is being provided by traditional vertically integrated utilities. On the other hand, rising debt burdens and lower electricity prices have recently put many independent power producers in financial peril. As a result, it is not clear how many IPPs will survive over the longer term, or who will build new capacity several years hence.

NOTABLE ENERGY DEVELOPMENTS

FERC PROPOSES STANDARD MARKET DESIGN FOR ELECTRIC POWER INDUSTRY

In October 2001, the United States Supreme Court affirmed the authority of the Federal Energy Regulatory Commission (FERC) to require non-discriminatory access to transmission lines for all power producers as a remedy for "undue discrimination" by incumbent utilities. The Court specifically upheld Orders 888 and 889, issued in 1996, which required investor-owned utilities to open up their transmission systems to competing power providers on a non-discriminatory basis. By extension, The Court's ruling also validated Order 2000, issued in 1999, which encouraged transmission-owning utilities to cede operational control of their high-voltage power lines to independent Regional Transmission Organisations (RTOs), while retaining ownership of these lines and revenue streams from their use. But few utilities have joined RTOs so far since this would eliminate their ability to operate their transmission facilities for competitive advantage.

In July 2002, FERC issued a Standard Market Design proposal to govern the structure and operation of wholesale US power markets. The idea is to make market practices across the broad expanse of the industry more coherent and consistent. All utilities that own, operate or control interstate transmission are to conform to this standard design by September 2004. Key elements include stronger inducements to participation in RTOs, active monitoring and mitigation measures to prevent market abuses, a centralised spot-power market to complement decentralised bilateral contracts for power, steps to enhance price and market transparency, and measures to encourage construction of needed power plants and transmission infrastructure.

RTOs: Under the Standard Market Design, all transmission owners and operators would have to join an RTO or contract with another independent transmission provider (ITP) to operate their transmission facilities. It is anticipated that if utilities have to cede operational control of their transmission in any case, they are likely to opt for the operational advantages of an RTO. RTOs and other ITPs will help FERC monitor the market for potential anticompetitive actions by market participants. Each RTO will also provide for seamless trading within the market it serves, so that transmission customers can avoid "pancaked" rates in which fees are paid to each utility that owns transmission assets needed to carry out a power transaction. Electricity sellers will pay a single access fee and a region-wide transmission rate which better reflects the true (lower) cost of transmission service and will therefore promote additional cost-saving transactions. RTOs will be overseen by a governing board of directors completely independent of market participants, as well as by an advisory committee of market participants and state government officials.

Bilateral Contracts: For the vast majority of power transactions which are made under bilateral contracts between buyers and sellers, the Standard Market Design provides for physical delivery of power through Congestion Revenue Rights, or CRRs. These are tradable financial rights for transmission between two points on the grid over a particular period of time. A secondary market will be created for such rights so that congested transmission pathways can be used by electricity suppliers who value the pathways the most. In addition, a new "network" transmission tariff will allow all transmission users to schedule power deliveries using multiple receipt and delivery points, with the same operational flexibility enjoyed by transmission owners.

Spot Market: To complement bilateral contracts, RTOs and other ITPs will administer voluntary markets for short-term transactions: spot markets for wholesale power, ancillary services and transmission congestion rights; a real-time "balancing" market to maintain reliable operations of the power grid; and a separate "day-ahead" market. The centralised spot-power market will be "security-constrained" with measures to ensure grid reliability and "bid-based" with buyers and sellers bidding the price at which they are willing to buy or sell power in any hour. This will ensure that electricity trade is not pursued at the expense of reliability and that reliability concerns do not needlessly constrain economically productive trade. Market-clearing prices will be provided transparently to all supply and demand-reduction sources to encourage efficient short- and long-run operations. A "circuit breaker" provision, to help prevent short-term price spikes, would bar bids above US$ 1,000 per megawatt-hour. The length and severity of price spikes will also be limited by allowing demand reduction measures to be bid into the spot market.

Investment: Several aspects of the Standard Market Design will promote required investment in new transmission capacity, generating plants and conservation. The market for CRRs will assign values to congestion that signal the need for investment to relieve transmission bottlenecks. Locational marginal pricing at each point on the grid will signal where investment in generation and transmission is needed to improve grid operations. Companies that invest in new transmission will be allowed to retain the fixed rights to the added power-transfer capacity. A generation adequacy requirement will compel companies serving retail customers to arrange sufficient supply and demand reduction resources to meet peak demand plus a 12 percent reserve margin. Infrastructure needs will be identified by RTOs through a planning process in each region that includes state regulators and local zoning authorities, so that projects meeting these needs can more readily obtain financing on the basis of anticipated returns. Such incentives and procedures should strengthen competition, limit tight supply situations that lead to short-run price spikes, and enhance the reliability of service.

DOE ISSUES NATIONAL GRID STUDY

A National Grid Study, issued in April 2001 and available on DOE's website at http://www.ntgs.doe.gov, recommends regulatory and market-based approaches to stimulate new investment in the U.S. interstate bulk power transmission system. While competition in regional wholesale electricity markets saves consumers some US$ 13 billion annually, the transmission system in place was not designed to support these markets. Nor has investment in the transmission system kept pace with investment in new generating facilities to serve growth in electric power demand. Transmission bottlenecks threaten reliability and cost consumers hundreds of millions of dollars each year. To deal with this problem, the study makes 6 general recommendations, around which 51 more specific recommendations are grouped:

- Increase regulatory certainty by completing the transition to competitive regional wholesale markets;
- Develop a process to identify and address "national interest" transmission bottlenecks;
- Avoid or delay the need for new transmission facilities by improving system operations;
- Coordinate voluntary demand-reduction, energy efficiency and distributed generation efforts within regional markets;
- Enforce penalties for non-compliance with reliability rules that are commensurate with the risks that violations of the rules create; and
- Create an Office of Electricity Transmission and Distribution in the Department of Energy.

CONGRESS SUPPORTS PERMANENT REPOSITORY FOR NUCLEAR WASTE

The US Congress has approved a resolution supporting the development of Yucca Mountain, in the state of Nevada, as a permanent geologic repository for high-level nuclear waste. This will be the first such repository in the US, relying on more than twenty years and US$ 4 billion of scientific study which demonstrates that Yucca Mountain is scientifically and technically suitable for development. Energy security, homeland security and environmental protection will all be enhanced by sitting a single nuclear waste repository at Yucca Mountain rather than leaving nuclear waste stranded in temporary storage locations at 131 sites in 39 states. In the next step, independent experts at the Nuclear Regulatory Commission (NRC) will review the scientific study of Yucca Mountain and consider the site for a license.

CLEAN COAL POWER INITIATIVE BEGINS

The US Department of Energy is receiving industry proposals valued at US$ 5 billion in the first round of President Bush's Clean Coal Power Initiative. The initiative pledges US$ 2 billion in federal cost sharing over the next ten years to advance technologies that can help meet growing electricity demand while also protecting the environment. Private sector proposals must agree to fund at least half the cost of any project selected. This initiative promotes a new generation of pollution control and power generating processes that reduce atmospheric emissions and, in many cases, greenhouse gas emissions to levels far below those of older, conventional coal-fired plants.

STRATEGIC PETROLEUM RESERVE TO BE FILLED FASTER

The Strategic Petroleum Reserve (SPR), the US emergency oil stockpile, is being filled at a faster rate, pursuant to President Bush's pledge to fill the SPR to its full 700 million barrel level. This is being done by increasing the "royalty-in-kind" exchange program, whereby oil produced from federal leases in the Gulf of Mexico is exchanged for oil going into the SPR. The government leases Federal Outer Continental Shelf tracts to crude oil producers who compensate the government with royalty oil. The goal is to fill the SPR by 2005 without using tax revenues to buy oil on the open market.

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VIET NAM

INTRODUCTION

Viet Nam is located in southeast Asia and shares borders with Cambodia, Laos and China. It has an area of 331,111 square kilometres and a population of about 78.5 million (2000). Its GDP in 2000 was about US$ 153 billion, and its GDP per capita was US$ 1,946 (both in 1995 US at 1995 PPP). The economy has experienced strong growth, with average annual increases of 7 percent in GDP and 10 percent in final energy consumption from 1991 to 2000.

Energy is a key component in Viet Nam's economy, supporting recent industrialisation, and contributing to export earnings. Viet Nam is well endowed with fossil energy resources such as oil, gas and coal, as well as renewables such as hydro, biomass and solar energy. As of 2000, total energy reserves stood at 420 MCM of oil, 617 BCM of gas, 3,325 Mt of coal and more than 17,000 MW of hydropower potential. Natural gas and crude oil are found mainly in the southern region (offshore), while coal reserves (mostly anthracite) are located in the northern region.

Table 41 Key data and economic profile (2000)

Key data		Energy reserves*	
Area (sq. km)	331,111	Oil (Proven)	420 MCM
Population (million)	78.52	Gas	617 BCM
GDP Billion US$ (1995 US$ at PPP)	152.83	Coal (Recoverable)	3,325 Mt
GDP per capita (1995 US$ at PPP)	1,946		

Source: Energy Data and Modelling Center, IEEJ.

*Institute of Energy, *Viet Nam 2000*.

ENERGY DEMAND AND SUPPLY

PRIMARY ENERGY SUPPLY

In 2000, Viet Nam's total primary energy supply was 14,152 ktoe, about 10 percent more than the year before. Oil was the most important fuel, making up 57 percent of primary supply. Coal made up 26 percent of primary supply, hydropower 9 percent and gas 8 percent. About three-fifths of indigenous energy production was used domestically while two-fifths, mostly crude oil and coal, was exported.

Viet Nam produced 16,513 ktoe of oil in 2000, more than four times as much as in 1991. Most oil exploration and development in Viet Nam occurs offshore in the Cuu Long and Nam Con Son Basin. Its first major refinery is under construction and should be operational by late 2005. Viet Nam currently exports all of its crude oil. Its largest customers are Japan, Singapore, the US and Korea. Imports of petroleum products were equivalent to 49 percent of production in 2000.

Gas production in Viet Nam began only in 1995 and is still quite low. As new gas fields and a new pipeline system came into service, gas production increased by 24 percent from 920 ktoe in 1999 to 1,137 ktoe in 2000. Rapid growth in production is expected in the next few years, perhaps with growth in exports as well, as new gas fields go into production. Most gas production comes from the Cuu Long basin and is associated gas from oil production. Pipeline capacity is currently inadequate to move available gas from the basin, and any surplus gas is flared.

Viet Nam's coal production has increased by 14 percent in 2000 to 5,580 ktoe. About 34 percent of coal produced is exported, mostly to Japan. The government is promoting coal use for electricity generation and expects to build several coal-fired power plants over the next few years.

Electricity output in Viet Nam grew by 13 percent in 2000 to 26,595 GWh. Most of the increase came from thermal plants, which generated 23 percent more electricity than the year before and accounted for 45 percent of output. Hydropower plants provided the remaining 55 percent of electricity output. To keep pace with the continued rapid demand growth that is anticipated over the next 20 years, the government is considering construction of several new hydropower, coal-fired and gas-fired plants as well as a nuclear power plant.

Table 42 Energy supply & consumption (2000)

Total Primary Energy Supply	(ktoe)	Total Final Energy Consumption	(ktoe)	Power Generation	(GWh)
Indigenous Production	23,669	Industry Sector	3,267	Total	26,595
Net Imports & Other	-9,517	Transport Sector	4,812	Thermal	12,044
TPES	14,152	Other Sectors	3,370	Hydro	14,551
Coal	3,676	TFEC	11,448	Nuclear	-
Oil	8,087	Coal	2,471	Others	-
Gas	1,137	Oil	7,049		
Others	1,251	Gas	-		
		Electricity & Others	1,928		

Source: Energy Data and Modelling Center, IEEJ (see http://www.ieej.or.jp/apec/database/selecttable.html)

FINAL ENERGY CONSUMPTION

Viet Nam's final end-use energy consumption grew very quickly during the 1990s, at an average rate of 11.4 percent per annum, from 4,419 ktoe in 1991 to 11,448 ktoe in 2000. In 2000 alone, final consumption grew about 10 percent for the economy as a whole and 12 percent for the industrial sector. Of the total consumed in 2000, transport accounted for a 42 percent share, industry for 29 percent, and other sectors for 29 percent. The industry share will rise as Vietnam builds up heavy industries like petroleum, metals, chemicals, fertilizer, power plants and building materials. By fuel shares, oil satisfied 62 percent of end-use demand in 2000, coal 22 percent, and electricity 16 percent. Electricity grew fastest, up by 15 percent in 2000, followed by coal with 12 percent growth and oil with 7 percent growth. Spurred by industrialisation and increased living standards, energy demand is expected to keep rising rapidly over the next decade.

POLICY OVERVIEW

The Prime Minister's Office, Ministry of Planning and Investment (MPI) and the Ministry of Industry (MOI) are responsible for formulating Viet Nam's energy policy and for regulating the quality of energy services. The Prime Minister approves energy-related policy statements.

Viet Nam is currently implementing reforms in the energy sector. The government is focusing on institutional restructuring, energy pricing and energy finance. Viet Nam is also trying to diversify its consumption of energy. By developing regional indigenous resources and expanding regional cooperation, Viet Nam hopes to minimise its dependence on oil. Another priority is to ensure that energy supplies are adequate to meet the needs of a growing population and to support socio-economic development. In this context, as well as to minimise harm to the environment, energy conservation and efficient use of energy are encouraged.

Viet Nam has devised an energy development strategy with the following goals:

- Make natural gas exploitation and utilisation a priority;
- Enhance production of coal, crude oil and petroleum products to 25-27 million tonnes, 25-30 million tonnes and to 18-20 million tonnes by 2020 respectively;
- Raise the share of electricity production generated from gas-fired power plants in order to improve the efficiency and stability of electricity supply;
- Promote energy trade through power system and gas pipeline interconnections with economies in the region;
- Diversify the ownership of energy production, retail supply and distribution companies;
- Study and utilise new and renewable energy, particularly on islands and in remote areas; and
- Study and utilise nuclear power as an alternative energy resource in the economy.

OIL AND GAS

The Viet Nam Oil and Gas Corporation (PetroVietNam) is a state-owned enterprise established in 1975 and controlled by the Prime Minister's Office. PetroVietNam is responsible for crude oil and gas exploration, production and transportation. The Ministry of Trade and Tourism (MTT) is responsible for crude oil exports, petroleum product imports, and the distribution of petroleum products to consumers through its Petrolimex and Petechim companies. Other state-owned and joint venture enterprises are also involved in trading petroleum products, but Petrolimex and Petechim meet about 60 percent of domestic demand for these products. The State Price Committee (SPC) is responsible for evaluating oil prices and submitting them to the government for approval.

OIL REFINERIES

The Prime Minister has approved a pre-feasibility study, prepared by PetroVietNam in cooperation with Mitsubishi Corporation and JGC Corporation of Japan, to build the country's second oil refinery and petrochemical complex. The US$ 2.49 billion project will be built in Nghi Son district in Thanh Hoa province, 125 kilometres south of Hanoi. Construction will start in 2003. The refinery is expected to begin operations in 2008, while the petrochemical facilities should be fully operational in 2010. The refinery will have a capacity of 7 Mt of crude oil a year, while the petrochemical complex will produce polypropylene and polyester fibres, other chemicals and plastics. The complex will include a harbour for loading products and a 100 MW power plant.

Viet Nam is currently building its first refinery, in Dung Quat in central Quang Ngai province. It is a US$ 1.3 billion joint venture between PetroVietNam, Russia's Zarubeznheft group, and a consortium led by France's Technip-Coflexip. When completed in 2005, the refinery will be able to refine 130,000 barrels a day or 6.5 Mt of crude oil a year. The plant will produce 2.08 Mt of automotive diesel, 1.95 Mt of unleaded gasoline, 1.33 Mt of diesel oil, and more than 100,000 tons of propylene each year. Some 30 to 40 percent of the project's registered capital will be sourced from PetroVietnam's revenue from crude oil sales, and the rest will be loans from domestic and foreign financial institutions.

In preparation for refining activities at Dung Quat, PetroVietNam will undertake several other projects in parallel. Three major petroleum storage systems will be located in Dinh Vu (Hai Phong city), Nha Be (Ho Chi Minh City), and the Cuu Long (Mekong) River Delta province of Can Tho, with capacities of 60,000 cubic metres, 50,000 cubic metres and 36,000 cubic metres, respectively.

PETROLEUM FINANCIAL GROUP

PetroVietNam is establishing a financial group to diversify its sources of capital, issue bonds on domestic and international markets, and booster its strategic long-term development. PetroVietNam's financial organisation is to comprise three entities: the PetroVietNam Financial Company (PVFC) and PetroVietNam Insurance, which are already affiliates, and a new

PetroVietNam Stock Company. In addition, PetroVietNam is expanding investment overseas, pursuing production-sharing contracts with Indonesian, Malaysian, Mongolian and Algerian partners. Recently, and it has secured two contracts to exploit petroleum overseas.

COAL

The Viet Nam National Coal Company (VINACOAL), established by the Prime Minister in 1994 and operating under a charter approved in 1996, produces most of the economy's coal. VINACOAL sets the sale price for domestic coal at a level where costs are equal to revenues or where firms break-even. The State Price Committee is responsible for evaluating coal prices and submitting them to the government for approval. Apart from this, market forces determine prices.

VINACOAL has earmarked VND 7.5 trillion to carry out power projects, VND 4.6 trillion for coal projects and VND 838 billion for trading and production until 2005. The corporation's coal projects are to meet growth in coal demand from 15 million to 17 million tonnes each year in the period from 2001 through 2005 to some 22 million tonnes in 2010. VINACOAL also has plans to build coal-fired power plants with a total capacity of 2,500 MW.

ELECTRICITY

Electricity of Viet Nam (EVN), established in 1995, reports to the MOI. EVN determines electricity policy and strategy for the sector. In 1998, EVN controlled seven distribution companies, four transmission companies, thirteen power plants and an energy research institute. However, an independent power producer (IPP) began generating electricity in 1998 and sold 500 GWh to EVN in 2000. The SPC is responsible for evaluating electricity prices and submitting them to the government for approval.

To meet growing electricity demand, EVN plans to build 37 new power plants by 2010, including 22 hydropower plants, 8 oil-and-gas-fired plants and 7 coal-fired plants. These plants and related substations and transmission lines are expected to require investment of US$ 22 billion, of which EVN will provide US $14 billion and foreign loans will provide the remainder.

BOT POWER PROJECT

The Asian Development Bank (ADB) has approved a US$ 50 million loan, as well as a political risk guarantee of $25 million for commercial lenders, for a 715 MW gas-fired combined-cycle power project in the south of Viet Nam, which is expected to cost US$ $480 million. The project will be developed and implemented under a build-operate-transfer (BOT) contract between the Ministry of Industry and the Mekong Energy Company Limited (MECO), which was set up specifically for the project. MECO is a joint venture between a subsidiary of Electricite de France (56 percent stake), a subsidiary of Tokyo Electric Power Company (16 percent), and Sumitomo Corporation of Japan (28 percent). Under the terms of the contract, MECO will operate the power plant for 20 years, during which time EVN will buy the plant's output under a power purchase agreement, and ownership of the plant will then be transferred to EVN.

The plant will be located at Phu My Power Complex in Ba Ria-Vung Tau Province, 75km southeast of Ho Chi Minh City. It will help prevent power shortages and reduce dependency on seasonal hydropower generation. PetroVietNam Gas Company will deliver natural gas to the project under a long-term agreement.

POWER GRID EXTENSION TO REMOTE AREAS

In May 2002, Viet Nam's government approved a VND 5.275 trillion (US$ 353 million) project to improve power supply to underprivileged and mountainous areas. The project will help develop renewable energy resources and improve the power sector's management and productivity. EVN will be the main investor in the project, which will be regulated by the Ministry of Industry and implemented in cooperation with People's Committees of the northern provinces of Ha Giang, Lai Chau, and Son La and the central provinces of Thanh Hoa and Nghe An.

ENERGY EFFICIENT LIGHT BULB PROGRAM

The World Bank has agreed to grant US $8.2 million to EVN for a program starting in 2003 to conserve some 120 GWh of electricity within three years. Under the program, EVN will buy compact fluorescent lamps (CFLs) and sell them at subsidised prices to about a million households. Since CFLs consume only 14 to 18 watts per hour while normal bulbs with comparable light output consume 100 watts per hour, the energy savings will be substantial.

NOTABLE ENERGY DEVELOPMENTS

ENERGY PRICE CHANGES

To help finance new electric power plants, the Prime Minister approved a proposal to increase electricity prices by an average of 12 percent, to VND 840/kWh (US 5.6 cents/kWh), as of October 2002. This is expected to increase production costs for key industrial sectors by 1 to 5 percent. The last electricity tariff increase had been introduced in October 1999.

The Ministry of Financial (MoF) revised import tariffs on petroleum and petroleum products on six occasions during 2002. A decision by MoF in August lowered the tariff on kerosene from 25 percent to 20 percent and the tariff on diesel from 15 percent to 10 percent.

POWER SECTOR

NEW COAL-FIRED PLANTS

The 100 MW Na Duong coal-fired power plant in Lang Son province, located near the Chinese border, is first of a series of coal-fired power plants which VINACOAL plans to build by the end of the decade as joint investments with the Japanese construction firm, Marubeni. Construction of the plant, which is expected to be in operation by 2004, began in March 2002. Advanced technology such as a circulating fluidised bed boiler will be used, allowing the plant to consume coal with a high sulphur content of 6 percent without any adverse impact on the environment.

A second 100 MW coal-fired plant, in the Cao Ngan district of Thai Nguyen Province north of Hanoi, is to be built by VINACOAL in cooperation with China's Harbin Power. Valued at US$ 85 million, the plant will use coal from nearby mines at Nui Hong and Khanh Hoa. A 300 MW coal-fired plant will be built by VINACOAL in the Cam Pha district of Quang Ninh province together with foreign partners who will form a joint stock company with capital of US$ 300 million.

Another coal-fired power plant with capacity of 300 MW has been approved for construction in the northern port of Hai Phong. The cost of the plant was estimated at US$ 628 million. EVN will provide 15 percent of the cost, and the remaining 85 percent will come from bank loans. The plant's first turbine group is expected to start operation late 2006, followed by its second turbine group in early 2007. The plant will help to alleviate electricity shortages in the northern provinces.

A gas-turbine power plant with capacity of 50 MW, in the southern province of Ba Ria-Vung Tau, began feeding into the national grid in May 2002. It brings the total capacity of the Ba Ria Thermal Power Plant to 321.8 MW. About US$ 45 million of the project's US$ 51 million cost was financed by Korea's Economic Development and Co-operation Fund.

NEW HYDROPOWER PLANTS

The Son La hydropower plant on the Da River, with a planned capacity of 2,400 megawatts and output of 8 to 9 TWh per year, was approved for construction in October 2002. The plant, which involves construction of a 215-metre dam, is scheduled for completion in 2015. Total investment in the project will be around US$ 4 billion of which about 70 percent will be raised from domestic sources and the remainder though foreign loans. Much of the investment will be used to relocate nearly 70,000 persons from the project site and to ensure safety of the population downriver of the dam (including Hanoi city) when the plant begins operation.

The Se San 3 hydro plant in the central highland province of Gia Lai, with a planned capacity of 260 MW and output of 1.2 TWh per year, has also been approved for construction. Total cost of the plant is around US$ 273 million, provided mainly from domestic investment funds with a modest loan from the Russian government for equipment and technical services. The first turbine group at the plant is expected to begin generating electricity in 2006. The plant will be the second-largest on the Se San River, after the 720 MW Yaly plant. It will contribute to the socio-economic development of ethnic minorities in the Central Highlands and help to maintain border security.

A feasibility study has been approved for the An Khe-Kanak hydro plant in the Central Highlands of Gia Lai province, to be completed in 2008. The 163 MW plant has an estimated cost of US$ 215 million, which will be financed from domestic sources.

NUCLEAR POWER FEASIBILITY STUDY

The Prime Minister has assigned the MOI, together with the Ministry of Science and Technology, the Atomic Energy Center, and the Institute of Energy, to carry out a pre-feasibility study for a 2,000 MW nuclear power plant in central Viet Nam to begin operation by 2017. The plant should be built in close proximity to the national electricity network and major demand centres, in order to minimise transmission losses. Ideally, it should also be near a seaport, so that materials can be easily transported. Six localities have been short-listed so far, including two sites in Quang Binh and Phu Yen provinces, two in Binh Thuan Province; and another two in Ninh Thuan Province. The study will be completed and submitted to the National Assembly for consideration towards the middle of 2003.

NEW TRANSMISSION LINE

EVN has begun construction of a third 500KV electric transmission line, extending for 60 km and connecting the three southern provinces of Ba Ria - Vung Tau, Ho Chi Minh City and Dong Nai. Starting in late 2003, the line will transmit power from three large oil-and-gas-fired plants at the Phu My Complex in Ba Ria - Vung Tau Province to industrial centres in southern Viet Nam. The three plants have a combined generating capacity of 1890 MW. The new 500KV line, joining the original 500kV North-South line and the second 500kV line that links the Central Highlands province of Pleiku with Ho Chi Minh City, will help ensure stable power supply in Viet Nam for the next 20 years. The estimated cost of the project is around US$100 million, of which a major portion will be financed by the Japan Bank for International Co-operation (JBIC).

A low-voltage power network for 78 communes in the Mekong delta has been built at a cost of US$ 34 million. The network will supply electricity to the six provinces of Bac Lieu, Kien Giang, Ca Mau, Soc Trang, Tra Vinh and Vinh Long where demand has been growing rapidly. With the network in place, all districts, 87 percent of communes and more than 2.34 million households with 73 percent of the population in the Mekong delta can access the electricity grid.

NEW NATURAL GAS PIPELINE SYSTEM

In October 2002, a joint venture by PetroVietnam and BP completed a 400km gas pipeline system to transport gas from the Nam Con Son basin to the Vung Tau Industrial Zone.

PetroVietNam began using the US$49 million Rang Dong and Bach Ho gas pipeline in July 2002. The pipeline is designed to transport associated gas from the Rang Dong and Bach Ho gas fields to the Dinh Co Gas Station which will supply fuel to the Phu My power and fertilizer plant. The pipeline, with a length of 40km, is capable of bringing ashore 800,000 cubic meters of gas per day, raising the corporation's daily output to 6 MCM.

INTERNATIONAL COOPERATION

PetroVietNam and Malaysia's national oil firm, Petronas, will join to further develop the Bunga Kekwa and Bunga Seroja oil fields in the Gulf of Thailand on the joint continental shelf area between Viet Nam and Malaysia. These fields have estimated reserves of 150 BCM and are expected to produce 2.5 BCM per year. The fields are due to be commissioned in 2003, feeding gas to the gas-power-fertilizer complex in Ca Mau province.

Vietnam has joined ASEAN economies in signing a memorandum of understanding (MoU) to build a trans-ASEAN gas pipeline at the recent ASEAN Energy Ministerial Meeting in Bali, Indonesia. Under the MoU, the 4,200km pipeline will be built at a cost of US $7 billion with seven systems connecting to the gas fields of Vietnam, the Philippines, Sumatra and Kalimatan islands in Indonesia, Malaysia, and the Gulf of Thailand. The MoU was scheduled to be submitted to the government for approval before the end of 2002.

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