ASIA PACIFIC ENERGY RESEARCH CENTRE

APEC ENERGY OVERVIEW

2003

DECEMBER - 2003

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APEC#………… ISSN …………

FOREWORD

Events in the last year or so have shown that most APEC economies continue to face a multitude of energy-related challenges. War and it's aftermath in Iraq, social unrest in Venezuela and Nigeria have resulted in perceived tight supplies, instability and consequential high and volatile prices in world oil markets. Fortunately, production disruptions in these 3 major producing economies did not result in any shortages, as such. The headline electricity blackout in the US Northeast and Ontario, Canada showed that even the most developed economies were not immune to severe and costly energy supply disruptions. For a variety of reasons, there were also actual and potential power shortages in China, Japan and New Zealand, in the last year.

For the most part, APERC and the APEC EWG and EGEDA in particular, promote and characterise the co-operative aspects of regional energy relationships within APEC. At times, there can be competition on the part of energy-importing economies to secure their energy supplies at least cost.

Thus energy adequacy and security issues remain high on the agenda of member economies. Most also face challenges in respect of funding the investment required to expand energy supply infrastructure to either satisfy expanding demand or to replace antiquated and inadequate facilities. The environmental challenges associated with energy supply and consumption remains as relevant as ever.

A broad overview of the energy situation, and developments in APEC economies is thus important to inform and help understand the energy status, emerging issues and policies that face member economies.

This is the third annual edition of the APEC Energy Overview. APERC has been delegated through the APEC EWG for the production of the Overview. In producing the Overview, APERC draws on macroeconomic and energy data contributed by member economies and held by the Energy Data and Modelling Center, Institute of Energy Economics, Japan. Wherever possible, data from this source has been used to ensure consistency and comparability between economies. We thank EDMC and member economies for their efforts in providing this data. Additional information has been obtained from public sources. The assistance of member economies, in particular the EWG and EGEDA delegates, have ensured that the information contained in this Overview is pertinent and as current and accurate as possible. We gratefully acknowledge member economy energy experts for their co-operation in the preparation of this Overview.

APERC researchers from most member economies are responsible for the compilation and preparation of the individual economy overviews. We thank them for their efforts.

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December 2003

CONTENTS

LIST OF ABBREVIATIONS

ABARE	Australia Bureau of Agriculture and Resource Economics
APEC	Asia-Pacific Economic Cooperation
APERC	Asia Pacific Energy Research Centre
ASEAN	Association of Southeast Asian Nations
bbl/d	Barrels per day
BCM	Billion cubic metres
Bt	Billion tonnes (Thousand Mt)
CO_2	Carbon dioxide
DOE	Departmnt of Energy (USA)
DOE	Department of Energy (the Philippines)
EDMC	Energy Data and Modelling Center (Japan)
EIA	Energy Information Administration (USA)
EVN	Electricity of Viet Nam
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
ktoe	Kilotonnes (thousand tonnes) of oil equivalent
kW	Kilowatts
kWh	Kilowatt-hour
LNG	Liquefied natural gas
LPG	Liquefied petroleum gas (propane)
MCM	Million cubic metres
Mt	Megatonnes (Million tonnes)
mtpa	Million tonnes per annum
MW	Megawatts (Thousand kW)
NZ	New Zealand
PNG	Papua New Guinea (or pipeline natural gas, depending on context)
PPP	Purchasing Power Parity
R&D	Research and development
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
VND	Viet Nam Dong

AUSTRALIA

INTRODUCTION

A continent between the Indian Ocean and South Pacific Ocean, Australia is the smallest continent and the sixth largest economy in the world. The continent is approximately 7.6 million kilometres mostly of plateaus, deserts, and fertile plains in the southeast. Its 19.4 million populations is concentrated along the eastern and southeastern seaboard, mainly in cities or major regional centres. Australia is a resource rich economy with a wide range of mineral, energy and other resources.

In the past eleven years until 2001, Australia's economic growth has averaged around 3.6 percent per year. In 2001, GDP was about US$ 467 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 during the last few years, owing much to the buoyant property market and strong domestic demand. Australia has avoided recession in the global slowdown, and is expected to continue to outperform most developed economies in 2004. Over 70 percent of Australia's international trade is with APEC economies and around 60 percent is within Asia.

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

Table 1 Key data and economic profile (2001)

Key data		Energy reserves*	
Area (sq. km)	7,600,000	Oil (MCM)	556
Population (million)	19.39	Gas (BCM)	2,550
GDP Billion US$ (1995 US$ at PPP)	466.92	Coal (Mt)	82,090
GDP per capita (1995 US$ at PPP)	24,084		

Source: Energy Data and Modelling Center, IEEJ. * Proved reserves at the end of 2001 from the bp Statistical Review of World Energy 2003.

ENERGY SUPPLY AND DEMAND

PRIMARY ENERGY SUPPLY

In 2001, the total primary energy supply in Australia was 105,780 ktoe. Of this total, 31 percent was oil, 43 percent coal, and 20 percent natural gas. Since 1980, gas use has grown by 4.8 percent per annum, coal by 2.6 percent per annum and oil by just .4 percent per annum.

Australia is the world's 4th largest producer of coal, behind three other APEC economies, the US, China and Russia, and the world's largest exporter of coal. In 2001, total indigenous production was 174,100 ktoe (329.3 Mt). 124,800 ktoe (72 percent) of this was exported. Much of the coal consumed locally 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, steel and aluminium. 2001 has seen world coal demand exceeding supply with demand continuing to grow strongly. Spot market prices for steam coal have increased from the low US$ 20s per tonne to the low US$ 30s with recent settlements in the mid-US$ 30s. Responding to firmer prices and increased coal demand in Asia, Australian coal producers have raised production levels. A number of planned projects have been commissioned during 2001, which together have the potential to add as much as 11.5 million tonnes of capacity.

In 2001, Australia is estimated to have had 2,550 BCM of natural gas reserves, more than double the 1,260 BCM in 2000, and up from 440 BCM in 1990. Natural gas production in 2001 was 30,200 ktoe. Of this, 20,967 ktoe (69 percent) was consumed domestically and the balance was exported as liquefied natural gas (LNG), almost entirely all to Japan. At 2001 production levels this amounts to around 76 years of reserves. 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 2001, Australia produced 32,912 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. In 2001, import dependency was around 16 percent, low by historical standards. Oil reserves in 2001 stood at 3,500 million barrels, well up on the 2,900 million barrels in 2000, up from 1,600 million barrels in 1990. The reserve to production ratio is around 13 years.

Australia produced 210,092 GWh of electricity in 2001. Production was mostly from thermal sources (91 percent) with a small amount from hydro (8 percent). Of thermal fuel consumption, was almost all is 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 for 2001

Primary Energy Supply (ktoe)		Final Energy Consumption (ktoe)		Power Generation (GWh)	
Indigenous Production	240,380	Industry Sector	33,455	Total	210,092
Net Imports & Other	-134,600	Transport Sector	28,985	Thermal	192,092
Total PES	105,780	Other Sectors	20,643	Hydro	16,778
Coal	45,524	Total FEC	83,083	Nuclear	-
Oil	32,912	Coal	5,917	Others	1,222
Gas	20,967	Oil	40,625		
Others	6,377	Gas	15,518		
		Electricity & Others	21,023		

Source: Energy Data and Modelling Center, IEEJ.

For full detail of the energy balance table see http://www.ieej.or.jp/apec/database/selecttable.html

FINAL ENERGY CONSUMPTION

In 2001, total end use energy consumption in Australia was 83,083 ktoe, an increase of 416 ktoe, 0.5 percent, over 2000. By sector, industry consumed 40 percent of energy, the transport sector 35 percent, and other sectors (including residential and commercial) 25 percent. By fuel source, petroleum products accounted for 49 percent of consumption, natural gas for 19 percent, and coal 7 percent. Electricity accounted for 25 percent of consumption. Since 1990, consumption of natural gas has grown at an annual rate of 3.6 percent, much faster than any other energy type.

The impediments to more widespread use of gas domestically are large distances between main sources of supply in the far west of the continent and centres of demand on the eastern seaboard, and 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 resulting in domestic natural gas demand remaining at 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 and promote a structure that maximises the economic and social potential of energy industries while working to 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. At this time, the Council of Australian Governments (CoAG) established an energy policy framework that facilitated (i) the creation of the Ministerial Council on Energy (MCE), and (ii) an Independent Review of Energy Market Directions.

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.

In November 2002, the Australian Government established the Energy Committee of Cabinet and the Energy Taskforce to develop a strategic plan for Australia's long term energy policy that brings together and enhances the many areas of policy work already underway, including energy productivity; environment; innovation; energy security; revenue; market and industry development; and resource development.

FURTHER ENERGY MARKET REFORM

Following a seven month process of submission review and public consultation, the final report of the Independent Review of Energy Market Directions was released on 20 December 2002. The report noted that while the energy reforms of the last decade have been beneficial, there is scope for further improvements.

- The Ministerial Council on Energy considered the Review's recommendations and on 1 August 2003 agreed to purse the following important and far reaching reforms for the energy sector:

- The Ministerial Council on Energy to be the single energy policy forum from 1 July 2004, with the Australian Government and Tasmania to join the National Electricity Market Ministerial Forum as full members in the interim;
- A national energy legislative framework to be agreed and developed on a collaborative basis;
- The establishment of two new statutory bodies - an Australian Energy Market Commission (AEMC) as a separate statutory rule-making body for market development purposes; and an Australian Energy Regulator (AER) to enforce regulations across the sector;
- Agreement to the objective of a national regulatory framework for distribution and retailing (other than retail pricing) under the Australian Energy Regulator, for implementation in 2006; and
- Ministers to take decision by year end on significant initiatives to improve the framework for transmission planning and investment, including on a national approach to transmission.

These are significant reforms to the market arrangements and will encourage the necessary private sector infrastructure investment required to meet Australian energy needs.

The main areas of immediate agreement involve improving the governance and institutional arrangements for the electricity and gas markets by providing a clear separation between the policy, market development, regulatory and market operation functions.

NATURAL GAS

In November 1997, all Australian governments agreed to a uniform national framework for third party access to natural gas transmission pipelines and distribution networks. All governments that have implemented the National Third Party Access Code for Natural Gas Pipelines Systems (the Gas Code) intended to improve competition in upstream and downstream markets, facilitate integration of transmission and distribution networks, and enhance security of supply in the domestic gas market.

REVIEW OF THE GAS ACCESS REGIME

The review of the Gas Access Regime was announced by the Productivity Commission in June 2003. The Review will address industry concerns including the effect of the current Regime on investment in the sector, and in the upstream and downstream markets; and how it might better facilitate a competitive market for energy services. The Commission is expected to report within a year, enabling the Ministerial Council on Energy to consider the recommendations of the review in 2004. Information on the inquiry and its progress is available online at http://www.pc.gov.au/inquiry/gas.

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 published a uniform national gas quality standard in late January 2003. Jurisdictions are considering measures to implement the standard.

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.

Australia's abundant gas resources and record as a reliable liquefied natural gas (LNG) supplier makes Australia ideally suited to play an increasingly important role in the Asian energy scene. Important policy initiatives by the Australian Government, such as the implementation of the LNG

Action Agenda, have provided a stable operating environment conducive to attract investment for export expansion.

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.

OIL

Australia is currently a net importer of liquid petroleum products. If Australia is to offset a projected decline in local production, further significant discoveries will need to be made. The House of Representatives Standing Committee on Industry and Resources recently released its report (Prosser Report) into exploration impediments. It recommended a range of measures in relation to current taxation arrangements and other investment incentives to stimulate exploration. The Government is developing its response to the report.

PETROLEUM PRODUCT

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

Australia's uranium exports administration has been significantly streamlined over the past two years with the granting of long-term export permissions strengthening Government controls by requiring exporters to comply with strict environmental, heritage and nuclear safeguard requirements. The changes also provide exporters with enhanced security over their projects while reducing their administrative burden in seeking export approvals on a shipment-by-shipment basis.

During 2002/2003 the uranium mining industry was subject to several Government reviews. The Bachmann Review conducted by the South Australian Government led to the implementation of improved incident reporting requirements by the South Australia uranium mines. The Lea review was conducted by the Northern Territory Government in 2002 and looked at the environmental regulations and reporting systems at Ranger and Jabiluka mines. Currently the outcomes of a Commonwealth Senate Inquiry into Uranium Mining, and a review of the environmental impacts of the In-situ leach mining process initiated by the South Australia Government are still pending.

ENERGY EFFICIENCY

NATIONAL FRAMEWORK FOR ENERGY EFFICIENCY

The Ministerial Council on Energy has endorsed a proposal for development of a National Framework for Energy Efficiency (NFEE). This Framework is being developed collaboratively between the Australian, State and Territory governments. The purpose of the NFEE is to achieve a step change in Australia's energy efficiency with the objective of unlocking the significant economic potential associated with increased implementation of energy efficient technologies and processes to deliver least cost approach to energy provision in Australia.

The NFEE has been drafted as a discussion paper and addresses why action is needed on energy efficiency; the technical and economic potential to improve energy efficiency; efforts and achievements to date; barriers to further action; and challenges to achieving more. Economic modelling has been commissioned to demonstrate the significant economic benefits that would be delivered by energy efficiency in terms of increased GDP and employment, and reductions in energy consumption and greenhouse gas emissions.

Background reports have also been prepared - a stock-take of Australian energy efficiency programs, barriers to energy efficiency; and statistical analysis of energy use in Australia.

As a national initiative, the framework will enable coordination and collaboration between various programs, thereby ensuring complementarity and maximisation of outcomes.

Information gathering from industry stakeholders on their response to the barriers and challenges will occur in early 2004. It is anticipated that after Ministerial Council on Energy approval, a draft NFEE will be released for public consultation later in 2004.

ENERGY TASK FORCE

Energy efficiency policy initiatives are also being considered in the context of the Prime Minister's Energy Task Force. The Energy Task Force is considering a range of energy efficiency initiatives, including minimum energy performance standards, energy efficiency in the Australian Government, energy service outsourcing and financing, and developing energy efficiency in industry.

NOTABLE RECENT ENERGY DEVELOPMENTS

NATIONAL ENERGY MARKET REFORM

As outlined in the Policy Overview, the Ministerial Council on Energy agreed to the following reforms to Australia's energy market on 1 August 2003:

- The Ministerial Council on Energy to be the single energy policy forum from 1 July 2004, with the Australian Government and Tasmania to join the National Electricity Market Ministerial Forum as full members in the interim;
- A national energy legislative framework to be agreed and developed on a collaborative basis;
- The establishment of two new statutory bodies - an Australian Energy Market Commission (AEMC) as a separate statutory rule-making body for market development purposes; an Australian Energy Regulator (AER) to enforce regulations across the sector; and
- Agreement to the objective of a national regulatory framework for distribution and retailing (other than retail pricing) under the Australian Energy Regulator, for implementation in 2006; and
- Ministers to take decision by year end on significant initiatives to improve the framework for electricity transmission planning and investment, including on a national approach to transmission.

ELECTRICITY INTERCONNECTION AND GENERATION

Basslink, a DC interconnection with a continuous rating of 480 MW between Tasmania and Victoria is under construction with an expected completion date in 2005. The interconnection will facilitate Tasmania's physical link to the National Electricity Market.

Proponents for the SA to NSW interconnector (SNI, previously SANI) have submitted applications for environmental approval under the Environmental Protection and Biodiversity Conservation Act.

The transfer capacity between NSW and Victoria has been increased to 1900 MW since 2002. Consideration 'is being given to a further increase in capacity of between 200 MW and 600 MW.

A 240 MW gas-fired power station is under construction in Western Australia and is due to be completed by late 2003. Additional capacity of 140 MW will be achieved through plant upgrades in NSW and Victoria by 2005. A total of 354 MW of wind generation projects have been approved in Victoria, South Australia and Tasmania, for completion by 2005.

Two gas-fired and two coal-fired power stations have been commissioned in the last year.

- Early this year, Intergen and Normandy commissioned the 852 MW coal-fired Millmerran power station in Southeast Queensland. Tarong Energy completed commissioning of the 450 MW coal-fired Tarong North Power Station near Nanango, Queensland in July 2003;
- In January 2003 the Australian Gas Light Company commissioned the 150 MW gas peaking Somerton Power Station at Somerton, Victoria; and
- Swanbank E, a 380 MW gas-fired power station near Ipswich, Queensland, was commissioned late last year by CS Energy.

Wind and hydro developments totalling 49.5 MW have been commissioned in Victoria, New South Wales and Tasmania over the last year, with an additional 87 MW of wind power expected to be commissioned in Victoria and South Australia by the end of 2003.

GAS PIPELINE DEVELOPMENT

Some of the major gas pipeline developments recently completed, under construction or proposed are described:

The $400 million Tasmanian Natural Gas Project comprises a 732 km sub-sea and underground gas pipeline that extends from the Australian mainland to Tasmania, and conversion of the Bell Bay Power Station to a gas-fired facility. The sub-sea pipeline from Longford in Victoria to Bell Bay in northern Tasmania was commissioned in early September 2002. Construction of the 430 km of onshore lateral pipelines from Bell Bay to Port Latta (in the north-west) and near to Hobart (in the south) was completed in late December 2002. The Tasmanian Government has been negotiating with a distributor for the roll out of a gas distribution network over 5-7 years.

A short-distance pipeline connecting the Longford gas processing plant to gas pipelines supplying NSW, Victoria and Tasmania was commissioned in late December 2002. This has established the first commercial gas trading hub in the Australian market.

The $500 million gas pipeline from Port Campbell in Victoria to Adelaide will initially enable gas to be transported from the Thylacine and Geographe gas fields in the Otway basin to markets in Victoria and South Australia. The pipeline, currently under construction, is expected to be commissioned by 1 January 2004.

AGL and Petronas propose to construct a $US 3 billion 2,900 km gas pipeline extending from PNG to Queensland or Northern Territory into the Moomba gas hub in South Australia. Several routes are being considered and a decision to proceed is subject to the joint venture signing up sufficient foundation customers.

A $500 million power infrastructure project in North and Central Queensland is based around the development of a new coal seam methane production field near Moranbah in the Bowen Basin. It involves the construction of a 391km-long, 250mm diameter pipeline from the field to Townsville and nearby Yabulu, proposed to begin late this year, and conversion of the existing open cycle oil-fired peaking plant at Yabulu to a 220 megawatt combined cycle, base-load gas-fired power station. Delivery of first gas to Townsville is expected in late 2004.

The Kambalda to Esperance Pipeline represents half of the $90 million project to establish an efficient power system for electricity generation at Esperance in Western Australia. The 341 km pipeline, which will carry gas originating from the Carnarvon Basin to a new gas turbine power station at Esperance Port, is expected to be commissioned in December 2003. Construction of the power station commenced in July 2003 is expected to begin commercial operations in early 2004.

The pipeline proponent is also investigating the viability of reticulating the Esperance Townsite with gas.

A competitive tender process has been approved for a proposed project to supply gas to the Central Ranges region of NSW. The proposal involves building a 320 km, $96 million pipeline extension from the terminus of the existing Central West Pipeline at Dubbo to Tamworth, which includes construction of a network of distribution pipelines to supply, at a minimum, prospective users in Mudgee, Tamworth and Gunnedah.

An exclusive heads of agreement has been signed by Woodside Energy, Eni Australia and Alcan Gove to supply natural gas from the Blacktip gas field in the Joseph Bonaparte Gulf to Alcan's alumina refinery and bauxite mining plant at Gove in the Northern Territory. The agreement proposes gas supply of 40 petajoules a year over 20 years from 2007. The agreement is conditional on Alcan and the Blacktip partners each making a final investment decision, obtaining regulatory approvals and concluding pipeline arrangements to transport gas from the Joseph Bonaparte Gulf to Gove.

ENERGY SECURITY

The security of Australia's energy supply has been of heightened interest in recent times. Like other governments around the world, the protection of key infrastructure encompassing the communications, IT, tourism, water, resources and energy sectors is of vital importance.

In response to the threat on security, the Australian Government Attorney-General and Minister for Communications, Information Technology and the Arts announced on 29 November 2002 that the Australian Government, States and Territories will share security information with the private sector through a new communications network or "one stop shop" on critical infrastructure protection – the Trusted Information Sharing Network (TISN). The Australian Government is also establishing a new Critical Infrastructure Advisory Council (CIAC) of State and Territory governments and business representatives to oversee the network and to report to the Attorney-General on critical infrastructure issues.

OIL

Following a modest level of *offshore* exploration activity in 2002, the first half of this year has brought some slight increases in exploration activity. A total of 36 offshore wells were drilled, the highest level since 1998, and there has been some increase in seismic surveying. However, *onshore* exploration drilling activity in the first half year in 2003 was at its lowest level for 25 years.

In April 2003 the Government released 35 new areas for offshore petroleum exploration. Bids for eighteen of the areas closed on 25 September 2003, with the remaining 17 areas being available until 10 April 2004.

NATURAL GAS

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 $2.6 billion per annum, from three gas liquefaction trains, along with LPG and crude oil.

In April 2001, the NWS Joint Venture announced they would proceed with the construction of a 4.2 mtpa fourth production train. The fourth LNG train will increase Australia's LNG exports to nearly 12 mtpa and is expected to meet growing demand in Asia. The AUD$2.5 billion expansion project is close to completion. In August 2002 China's State Development Planning Commission announced the purchase of 3.3 mtpa of LNG for the Guangdong terminal.

There are a number of hydrocarbon fields containing mainly natural gas in the Timor Sea between Australia and the newly independent nation of Timor Leste. One of these fields, the Bayu Udan field, is estimated to contain 3.4 tcf of gas with 400 million barrels of condensate and LPG. The gas project from Bayu-Undan was given the final go ahead in June 2003. The project will consist of a 500km off-shore pipeline to Darwin Harbour where construction of a LNG plant has commenced. The LNG plant will have a capacity of 3.2 mtpa of LNG, with a contract to supply Tokyo Electric Power Company and Tokyo Gas for a 17 year period commencing in the first quarter of 2006. Following signing of the Timor Sea Treaty, the two countries have agreed to split the royalties from the Bayu Undan field 90 percent to Timor Leste and 10 percent to Australia.

The larger Greater Sunrise field is estimated to contain 7.7 tcf of gas and 299 million barrels of condensate. An International Unitisation Agreement (IUA) for the development of the Greater Sunrise field was signed between Australia and Timor-Leste on 6 March 2003. The IUA provides for the apportionment of revenue from the field in the ratio of 79.1 to 20.1 percent between Australia and the Joint Petroleum Development Authority that administers the area of the Timor Sea shared by both countries. The IUA will enter into force upon written notification of passage of implementing domestic legislation in the two countries. 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.

PETROLEUM PRODUCTS

In March 2003 the Minister for Industry, Tourism and Resources released a draft reform package for the Downstream Petroleum Sector. The reform package provides for:

- A national Terminal Gate Pricing mechanism;
- More transparent contractual arrangements; and
- Access to a dispute resolution scheme.

The reform package is being finalised to enable consideration by Government in late 2003.

COAL

The Australian coal industry is going through a period of major expansion. Capital expenditure of $A2.5 billion has already been committed to projects with a combined capacity of 45 Mt per annum. Coal port terminals are expanding to accommodate this expansion. Competition reforms have been progressed 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 over the medium to longer term. The price of high quality coking coal has been buoyant, reflecting tight supply and strong growth in steel production particularly in China.

URANIUM

Australia is the world's second largest uranium producer after Canada and has the largest known uranium stocks of any economy.

There are currently three operating uranium mines in Australia:

- Ranger in the Northern Territory exported 4,244 tonnes of U_3O_8 in 2002;
- Olympic Dam in South Australia exported 2,615 tonnes of U_3O_8 in 2002. Production during 2002 was adversely affected by rebuilding and major repairs following fires in both the copper and the uranium solvent extraction circuits. Plans are currently being developed to significantly expand the project, raising U_3O_8 output to greater than 8,000 tonnes per year; and

- Beverley in South Australia. The mine commenced operation in late 2000 and exported 779 tonnes of U_3O_8 in 2002. Approved production capacity is 1,000 tonnes per year.

Formal government approval to develop the Honeymoon ISL project in South Australia was announced in late November 2001 granting approval for production up to 1,000 tonnes per annum of U_3O_8. In May 2003, Southern Cross Resources announced that the project had been placed on hold pending improvements in uranium prices and equity markets.

The Northern Territory Government has approved the long-term care and maintenance of its Jabiluka mine. Energy Resources of Australia are working on an Agreement with the Traditional Owners of Jabiluka, the Mirrar people, and the Northern Land Council on a care and maintenance plan.

Australia exported U_3O_8 to the following APEC countries in 2002:

- USA: currently Australia's largest market - 2790 tonnes;
- Japan: 2688 tonnes;
- Republic of Korea: 576 tonnes, and
- Canada: 170 tonnes.

RENEWABLE ENERGY

The Government provides assistance to the renewable energy industry via the Mandatory Renewable Energy Target (MRET), and through the funding of over A$300 million for programs like the Renewable Energy Equity Fund and the Renewable Remote Power Generation Program. The Renewable Energy Action Agenda sets out a strategic plan to achieve a sustainable and internationally competitive renewable energy industry.

MRET has already stimulated A$200 million of investment in new renewable energy projects, as well as the upgrading of existing generators. An independent review of the MRET legislation has commenced, with findings to be reported to Parliament in January 2004. The review will consider the achievements of the scheme's first phase in light of the Government's greenhouse and industry development goals. It provides an opportunity to consider changes that might further encourage growth and investment in the renewable energy industry, including possible increases in the target.

HYDROGEN

Looking towards the future, the Australian Government initiated a hydrogen project early in 2003 which investigated the potential benefits of the use of hydrogen in Australia's long-term energy supply. The project comprised a study of the hydrogen economy and an international conference on hydrogen that was held in Broome, Western Australia in May 2003.

The national hydrogen study considered existing and future energy supplies; technical developments; industry opportunities; and infrastructure and investment requirements. Economic, financial, regional and environmental issues were within the scope of the study. The study report was completed in September 2003 and is currently under consideration by the Australian Government.

COAL21 AND CARBON SEQUESTRATION

The Australian coal industry has initiated a partnership with government, coal researchers and related industry sectors to develop a national clean coal strategy. The first phase of COAL21 is to develop by the end of 2003 a national plan of action for reducing greenhouse gas emissions from the use of coal in electric power generation. An issues paper was circulated for broader stakeholder and general public consideration in August 2003. The partnership between government and industry under COAL231 has also been used to support active participation by Australian stakeholders in bilateral cooperation with other countries under Climate Action Partnerships and Australia's participation in the Carbon Sequestration Leadership Forum.

Carbon sequestration has the potential to make an important contribution towards meeting Australia's future greenhouse commitments. A new Cooperative Research Centre on Greenhouse Technologies or the CO_2CRC was established in 2003 to work with industry and other research agencies to develop geological sequestration as a practical greenhouse response measure for Australia. The CSIRO has also established a flagship program which gives priority to developing low emissions technologies for power generation in Australia. International collaboration by Australia on geological sequestration is being advanced particularly through the Carbon Sequestration Leadership Forum, but also through the Intergovernmental Panel on Climate Change (IPCC) where Australia is supporting a lead author and hosting meetings associated with the IPCC's report on Sequestration. Australia is hosting the second Ministerial Meetings on the CSLF in September 2004, has been elected Vice Chair of the CSLF Policy Working Group and is taking a leading role in its stakeholder and legal, financial and regulatory taskforces.

Australia is also hosting the International Energy Agency, Asia Pacific Zero Emissions Technology Conference on the Gold Coast from 17-20 Feb 2004. This Conference will also include an APEC Energy Working Group Workshop on Zero Emissions Technologies.

GREENHOUSE

The Government will continue to develop and invest funding in 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, if not more than most other industrialised countries on climate change.

Australia 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 7 July 2003, the governments of Australia and New Zealand announced a Climate Change Partnership to strengthen practical collaboration on ways to address climate change. A number of possible areas for action have been identified including:

- Engaging with business and local government on technology development, policy design and implementation;
- Building on existing cooperation on energy efficiency;
- Measuring and reducing emissions from the agricultural sector;
- Further enhancing climate change science and monitoring; and
- Working with Pacific Island nations to address the regional challenges posed by climate change.

This follows the announcement in July 2002 of a number of cooperative projects under a Climate Action Partnership between the United States and Australia. The projects cover climate change science and monitoring, stationary energy technologies, greenhouse accounting in the forestry and agriculture sector, engaging with business in relation to technology development and policies/tools, and collaborating with developing countries to build capacity to deal with climate change.

Cooperative bilateral arrangements to address climate change with Japan, the European Union and China are also in development.

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BRUNEI DARUSSALAM

INTRODUCTION

Brunei Darussalam (the Abode of Peace) is located on the northwest side of the island of Borneo. It has a total land area of about 5,765 square km and a 161 km coastline 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 2001, the population of Brunei Darussalam was about 0.34 million.

The real gross domestic product (GDP) at current price in 2001 was recorded at US$4,156.5 million and the GDP per capita was at US$12,514 an increased of 3 percent compared to the previous year, mainly attributed by oil and gas sector.

The Steady political situation and excellent vision of His Majesty the Sultan and Yang DiPertuan have made it possible for Brunei Darussalam to achieve sustainable economic prosperity and stability. Brunei Darussalam's economy has been heavily relying on oil and gas since its discovery in 1929. The oil and gas sector is the main source of the economy's revenue which constitutes about 90 percent of Brunei Darussalam's exports and about 37 percent of its GDP. To further sustain and strengthen the oil and gas industry, his Majesty's Government is promoting and pursuing an economic diversification policy thus actively pursuing the development of the new upstream and downstream activities.

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

Table 3 Key data and economic profile (2001)

Key data		**Energy reserves****	
Area (sq. km)	5,765	Oil (MCM)	223
Population (million)	0.34	Gas (BCM)	391
GDP at current prices (Million US$)*	4,156.5	Coal (Mt)	-
GDP per capita (US$)*	12,514		

Source: Energy Data and Modelling Center, IEEJ. * Brunei Darussalam Key Indicators 2003.

** Proved reserves, end of 2001, BP Statistical Review.

ENERGY DEMAND AND SUPPLY

PRIMARY ENERGY SUPPLY

In 2001, the total primary energy supply of Brunei Darussalam reached 2,422 ktoe, increasing by 10 percent compared to 2000. Brunei's oil and gas production was 17,519 ktoe, an improvement of 0.6 percent from its 2000 production of 17,066 ktoe, and 89 percent of which was exported. Natural gas represents 77 percent of the total energy supply while oil represents 23 percent.

Total proven crude oil reserves are 223 MCM. Oil is exported mostly to Japan, Korea, Singapore, Chinese Taipei and Thailand. Brunei Darussalam has natural gas reserves of 391 BCM, and the long-term prospects for its production is thought to be excellent. Most of Brunei's LNG is exported to Japan, with a small amount going to South Korea. Despite the good prospects for the growth of oil and gas exports, Brunei Darussalam's economy is still vulnerable to movements in global oil prices. The drop in global oil and gas prices (as was experienced in the past) have continued to weighed down on Brunei Darussalam's economy, including that of its trading partners, which resulted to reduced energy demands.

However, Brunei Darussalam's economy is expected to remain strong with the implementation of the 8th NDP (2001-2005). With the US$4 billion budget allocated for the implementation of the 8th NDP, the economy is optimistic that its targeted growth rate of 5-6 percent will be achieved.

In 2001, the economy's total installed generating capacity under the Department of Electrical Services (DES) and the Independent Power Utility namely the Berakas Power Company (BPC), reached 810.1 MW. DES and BPC each have an installed capacity of 552.5 MW and 257.6 MW respectively. Almost all, or 99.7 percent of the total electricity generated was supplied by natural gas. Total generation for 2001 was 2,910 GWh, about 2.4 percent higher than 2,842 GWh in 2000.

FINAL ENERGY CONSUMPTION

In 2001, the total final energy consumption of 635 ktoe went down by 0.2 percent from 636 ktoe in 2000. The shares of the three sectors remain unchanged. 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 contributed the largest share with 62 percent of consumption, followed by electricity at 34 percent and gas at 4 percent.

Table 4 Energy supply & consumption for 2001

Primary Energy Supply (ktoe)		Final Energy Consumption (ktoe)		Power Generation (GWh)	
Indigenous Production	17,519	Industry Sector	84	Total	2,910
Net Imports & Other	-15,098	Transport Sector	328	Thermal	2,910
Total PES	2,422	Other Sectors	222	Hydro	-
Coal	-	Total FEC	635	Nuclear	-
Oil	574	Coal	-	Others	-
Gas	1,847	Oil	395		
Others	-	Gas	26		
		Electricity & Others	214		

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 8th NDP, place 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 promotion of 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 the end in view of achieving more balanced socio-economic development. The government is also working on improving the economy's investment climate to attract and encourage the private sector to play a more active and important role in the development of the economy.

OIL AND GAS

Prior to 1963, all mining activities (including petroleum), were regulated by the Mining Act. In 1963, the Government has introduced the Petroleum Mining Act to cover all petroleum mining activities. The latter came with its own model of concessionary agreements where most exploration and production operations in the economy were carried out. 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 with respect to any onshore state land or offshore state land for purposes of exploring or mining petroleum. Any person interested to bid shall therefore conform to such terms and conditions, 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. One of its 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 extend Brunei Darussalam's oil reserves, the Brunei Oil Conservation Policy was introduced in 1980. It came into effect in 1981 and has resulted in oil production of 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 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.

NOTABLE ENERGY DEVELOPMENTS

DEVELOPMENT OF DOWNSTREAM OIL AND GAS INDUSTRY

In an effort to diversify Brunei Darussalam'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 2001 and has identified the following potential industries to be developed in Brunei Darussalam:

- 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 2002, Petroleum Brunei called for expressions of interest for investment in the petrochemical projects to be located at the Sg. Liang Industrial site in the Belait District from which investors were shortlisted to conduct their Detailed Feasibility Study (DFS) on their proposals. The DFS reports were submitted in Q3, 2003 from which selection for project implementation will be by first half 2004.

In January 2003, the Brunei Economic Development Board (BEDB) has announced it's "two-pronged strategy" that included plans for the development of Sungai Liang, Pulau Muara Besar and the identification of other industry clusters for FDI, as well as for local investment. BEDB has reviewed one of its current policies and procedures that an approval has been granted by His Majesty's Government for the change of policy on the ownership and lending of industrial land. This would enable BEDB to lease, sublease or sublet industrial lands and buildings to investors and for the assets involved to be changed as collateral for bank financing.

LNG SIXTH TRAIN EXPANSION OPPORTUNITY

Brunei LNG has embarked on a program to expand its present capacity of 7.2 million tonnes per year to 11.2 million tonnes per year by 2010. Brunei LNG will also refurbish existing capacity to extend its operating life to 20 years, or up to 2033. It is also aiming for continued LNG sales beyond 2013. Around B$2.4 billion is earmarked for investment over the next 13 years to support such activities. The feasibility study will begin early 2003, and a final investment decision is expected in 2005.

OPENING OF NEW PETROLEUM AREAS

In the new petroleum areas, two consortia bid for Block J (5,020 sq km), and one for Block K (4,944 sq km) were received. Both blocks are located offshore in the deep water Exclusive Economic Zone (EEZ). There was no bid for the onshore Block L (2,254 sq km), which is still 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 and Amerada Hess hold the remaining 25 percent and 15 percent respectively. The government has also awarded exploration rights to Block K to a joint venture led by Shell International (the designated operator) owning 50 percent interest, including Conoco and Mitsubishi with 25 percent interest each.

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, almost 100 percent of the population has been provided with electricity from the power grid. Slightly over a thousand of the people living in remote villages, still remain detached from the grid and have no access to electricity. Small portable generators are used to provide for its electricity needs. Electricity demand is projected to grow to about 7 percent in 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 will add 99 MW of installed capacity to the system and a new twin overhead line circuit that will link with the new power plant in Tutong District. Target completion is by end of 2002.
- Construction of a new 165 MW thermal power plant in the Tutong District. Fuel pipeline and metering station have been completed, and earthwork is currently being carried out. The project is however scheduled to be re-tendered calling specifically for a combined-cycle plant.

- Extension of Lumut Co-generation Plant. This involves the installation of six generator sets with an installed capacity of 66 MW. Preliminary design work has been completed
- 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 Darussalam plan to reduce the 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 31 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 2001, its GDP amounted to roughly US$803 billion (in 1995 US$ at PPP), or US$25,841 per capita. Due to this high standard of living, cold climate, long distances between major cities, and many energy intensive and bulk goods industries, Canadians are heavy energy consumers. Canada's final energy consumption per capita in 2001 was 6.0 toe or about four times the APEC average.

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. The economy slowed substantially in 2001, along with that in the neighbouring United States. But real GDP growth recovered from 1.9 percent in 2001 to 3.3 percent in 2002. However, growth appeared to falter in 2003 due to SARS, restrictions on beef exports, appreciation of the Canadian dollar, and the August blackout which disrupted economic activity in Ontario. Inflation remained low, with consumer prices increasing 2.6 percent in 2001 and 2.2 percent in 2002. Unemployment averaged 7.2 percent in 2001 and 7.7 percent in 2002.

Canada is the fifth largest energy producer in the world (behind the United States, Russia, China and Saudi Arabia) and is 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 2001, energy reserves included 680 MCM of conventional crude oil, 27,770 MCM of oil in oil sands, 1,615 BCM of natural gas, 6,294 Mt of coal, and 452 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.

Table 5 Key data and economic profile (2001)

Key data		Energy Reserves**	
Area (square km)*	9,984,670	Oil (MCM)***	680
Population (million)	31.08	Gas (MCM)***	1,615
GDP Billion US$ (1995 US$ at PPP)	803.2	Coal (Mt) - Recoverable	6,294
GDP per capita (1995 US$ at PPP)	25,841	Oil Sands (MCM)***	27,770

Source: Energy Data and Modelling Center, IEEJ. * Statistics Canada. ** National Energy Board.

*** Established reserves of oil, gas and oil sands are equal to the sum of all proven reserves and half of probable reserves.

ENERGY DEMAND AND SUPPLY

PRIMARY ENERGY SUPPLY

In 2001, Canada's energy production exceeded 385 Mtoe, of which natural gas constituted 40 percent, crude oil 36 percent, coal 9 percent, hydropower 7 percent, nuclear power 5 percent and other sources 3 percent. Gross energy exports, primarily crude oil and natural gas from the western provinces, amounted to nearly 207 Mtoe or 54 percent of energy produced. But there were also substantial energy imports of some 83 Mtoe, mostly crude oil by eastern provinces, so net exports were just 32 percent of production

Taking account of exports, imports and stock changes, Canada's domestic primary energy demand in 2001 totalled roughly 262 Mtoe or 68 percent of production. Of the primary energy ~~supply~~ demand, 37 percent was provided by crude oil and petroleum products, 27 percent by natural gas, 14 percent by coal, 11 percent by hydropower, 7 percent by nuclear power and 4 percent by other fuels.

Exploration for oil and gas declined in 2002 from record levels in 2001. About 14,600 wells were drilled in 2002, a decline of 15 percent from 17,200 wells in 2001. The main focus of exploration was on gas, as about 63 percent of all wells completed were gas wells. During 2002, oil production increased by 6 percent and gas production declined by 1 percent from 2001 levels. As energy prices moderated and gas exports declined slightly, total gross export earnings for natural gas, petroleum, coal and electricity fell from a record CAN$58 billion in 2001 to CAN$43 billion in 2002.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 30 percent of production in 2002 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. A generally strong oil price environment has buoyed conventional oil and bitumen production in the WCSB and encouraged expansion in newly developed resource basins on the East Coast.

Exports account for a large portion of Canada's oil and gas production. Crude oil production in 2001 exceeded 138 Mtoe, of which 70 percent was exported, mainly from western Canada. Meanwhile, nearly 58 Mtoe of oil was imported into eastern Canada, so that net oil exports were equivalent to just 28 percent of production. Gas production in 2001 totalled more than 152 Mtoe, of which net gas exports of more than 85 Mtoe were equivalent to 56 percent. The 1990s saw average annual growth of 3.6 percent in net oil exports and 9.2 percent in net gas exports. For oil exports, growth slowed to less than 1 percent in 2001 and around 3 percent in 2002. Gas exports grew just 5 percent in 2001 and declined by 2 percent in 2002. But the long-term prospects for oil and gas exports remain bright due to robust demand in the US, expanding pipeline capacity, and continued discoveries.

Table 6 Energy supply and consumption for 2001

Primary Energy Supply (ktoe)		**Final Energy Consumption (ktoe)**		**Power Generation (GWh)**	
Indigenous Production	385,366	Industry Sector	69,459	Total	587,655
Net Imports & Other	-123,103	Transport Sector	53,061	Thermal	177,615
Total PES	262,263	Other Sectors	62,720	Hydro	333,145
Coal	35,857	Total FEC	185,239	Nuclear	76,695
Oil	97,575	Coal	3,966	Others	200
Gas	71,712	Oil	77,700		
Others	57,119	Gas	49,861		
		Electricity & Others	53,712		

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

Canada generated about 588 TWh of electricity in 2001, nearly 3 percent less than in 2000. Hydropower predominated with a 57 percent share, followed by thermal plants with 30 percent and nuclear power at 13 percent. Natural gas is increasingly favoured over coal for incremental thermal generation, owing to its reputation as a cleaner fuel and the availability of cost-effective combined-cycle generators. There is substantial two-way electricity trade with the western United States, mostly among hydropower facilities. Net electricity exports to the US in 2001 amounted to roughly 4 percent of production.

Canada also exported significant amounts of metallurgical coal, chiefly to Asian markets through the late 1990s. Export volumes have, however, declined in recent years. The only significant import of coal is for thermal requirements in Ontario. These have volumes have increased since 1999 owing to the temporary shutdown of seven nuclear units in the province. Finally, Canada remains the world's leading producer and exporter of uranium, of which it accounts for nearly a third of world output

FINAL ENERGY CONSUMPTION

In 2001, total end use energy consumption in Canada amounted to more than 185 Mtoe. Industry accounted for 37 percent of energy use, residential and commercial buildings for 32 percent, transport for 29 percent, and agriculture for 2 percent. By fuel source, petroleum products accounted for 42 percent of consumption, natural gas for 27 percent, electricity for 23 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 about 70 percent of energy use while lighting, air conditioning and electronic equipment account for the other 30 percent. Growth in consumption has been slow, averaging just 0.9 percent per annum in the 1990s. Significant improvements in the energy efficiency of buildings, HVAC (heating, ventilation and air conditioning) and electronic equipment have occurred. But these efficiency gains have been offset by demand growth associated with increases in population and GDP, by greater market penetration of household appliances and office equipment and by a strong preference for larger homes.

Three industries - pulp & paper, petroleum refining and iron & steel - account for approximately 6 percent of Canada's GDP yet are responsible for more than 40 percent of industrial energy consumption. Energy is used to power equipment, generate process heat, and provide raw material in production processes. Energy consumption in the industrial sector grew on average 1.3 percent per annum during the 1990s. Growth in energy consumption was boosted by strong economic growth but moderated by efficiency improvements in some key industrial sub-sectors.

With strength in both passenger and freight traffic, energy use grew faster in the transportation sector than in any other sector during the 1990s, at an average of 2.3 percent per annum. Petroleum products dominate the sector, accounting for 89 percent of its energy consumption in 1999. Four-fifths of transport demand, in terms of distance travelled, is met by road transport. Light trucks, including sport utility vehicles and minivans, which consume far more fuel per kilometre than cars, continue to be popular for passenger transport. Minimal fuel efficiency improvements in new vehicles, strong market preferences for enhanced performance and significant increases in average distance travelled per vehicle have contributed to energy consumption growth. In the area of freight transport, energy use has been boosted by growing demand and a shift away from railways towards more energy-intensive truck transport.

POLICY OVERVIEW

In Canada, jurisdiction over energy matters is shared between the provincial and federal governments. The constitution gives the provinces ownership of natural resources which thus have authority over the conservation and management of these 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 Natural Resources Canada (NRCan) and other government departments including Environment Canada, the Department of Fisheries and Oceans, and Indian and Northern

Affairs Canada, the federal government works with 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 the sustainable development of resources and limiting environmental impacts. Natural Resources Canada intervenes in areas where the market does not adequately support these policy objectives. NRCan implements policies and programmes which encourage scientific and technological research, promote energy efficiency and assist the development of renewable and alternative energy sources.

OIL AND GAS MARKETS

Wellhead oil and natural gas prices in Canada have been fully deregulated since the Western Accord between the federal government and energy-producing provinces was reached in 1985. 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 essentially leaving it to the market to satisfy legal requirements for natural gas to 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 has been 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 provinces have taken measures to make electricity markets more competitive. Such measures include the unbundling of major utility functions into transmission, generation, distribution and marketing segments, with provisions for fair access of competing generators and suppliers to the transmission grid.

To maintain access to 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. Several Canadian utilities have taken steps to coordinate their operations with regional transmission organisations (RTOs) being set up under FERC proposals for standardised market design. Manitoba has signed a coordination agreement with the Midwest Independent System Operator. 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.

Alberta was the first province to reform its power markets. 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 sometimes faced price hikes of 80 percent or more since retail competition was introduced. But due to low reserve margins at the time that competition was introduced, it is likely that significant price hikes would have occurred under traditional cost-of-service regulation as well. As new supply is added, it is expected that prices will come down. Meanwhile, temporary price rebates have offered customers some relief on power bills.

In Ontario, Canada's most populous province, wholesale and retail electricity markets were opened to competition in May 2002. But the retail rate for smaller customers, representing half the total load, was capped through May 2006 at the May 2002 rate of 4.3 cents per kWh. The new Liberal government of Ontario has recently indicated its intention to lift this cap. The groundwork for reform in Ontario was laid by the Energy Competition Act of 1998 which ended the monopoly on power 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 transmission entity, Hydro One, remains publicly owned and provides access on non-discriminatory terms to all competing suppliers. Distribution companies, most of which are municipal electric utilities, were required by the Act to separate their wires businesses, which remain regulated as natural monopolies, from their retail supply businesses, which are competitive. The competitive operation of Ontario's power market is overseen by an Independent Electricity Market Operator.

Restructuring has not advanced as quickly in other provinces and may be subject to further reviews given the experience of Ontario, California and the August 2003 blackout. As noted below, several provinces - British Columbia, Nova Scotia and New Brunswick have initiated some steps toward restructuring.

ENERGY END USE MARKETS

To promote energy efficiency and conservation in end use markets, the Government of Canada relies on a variety of policy instruments. These include leadership by example, voluntary measures, equipment and product labelling, financial 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) with a mandate to strengthen and expand Canada's commitment to energy efficiency. OEE manages energy efficiency measures in all energy end-use sectors and alternative fuel initiatives in transport to overcome barriers of inadequate information and knowledge, institutional deterrents, and financial and economic constraints in the energy end-use market. The OEE has developed a set of progress indicators to track the impact of these measures.

Programmes aimed at improving energy efficiency are sponsored not only by the Government of Canada but also by provincial and territorial governments, municipalities, utilities and some non-governmental organisations. Over the period from 1990 through 2001, the OEE Index indicates an overall energy efficiency improvement of about 10 percent, which translates into energy savings of 764 petajoules in 2001. An annual assessment of trends in energy use are published in a technical report entitled *Energy Efficiency Trends in Canada*.

ENERGY AND ENVIRONMENT

Canada was one of the 160 countries that negotiated the Kyoto Protocol in December 1997 under the United Nations Framework Convention on Climate Change. Under this Protocol, Canada's target is to reduce its greenhouse gas emissions to 6 percent below their 1990 levels by the first commitment period of 2008-2012. This is a challenging target for Canada, a cold-climate economy with long distances and energy-intensive industries. According to business-as-usual scenarios, emissions in Canada should rise significantly between 1990 and 2010, fuelled by economic and population growth. To achieve its Kyoto target, Canada will have to reduce its 'business-as-usual' emissions by 29 percent or 240 million tonnes.

From 1998 through 2002, intense discussions took place between the federal government and its provincial and territorial counterparts. Stakeholders were also actively engaged under this National Climate Change Process to identify best options to reduce emissions in the various sectors of Canadian society. Discussions and consultations led governments to take some initial actions on climate change. For instance, a *First National Climate Change Business Plan* was released in October 2000 and identified emissions reduction actions to be undertaken by federal, provincial and territorial governments. The federal component of this Business Plan was the *Government of Canada Action Plan 2000 on Climate Change*, which represented a financial commitment of CAN$500 million. Overall, federal financial commitments during the period 1998 to 2002 amounted to CAN$1.7 billion for investments in climate science, mitigation, and the development of new long-term technologies.

In December 2002, the Government of Canada officially ratified the Kyoto Protocol. This decision reconfirmed Canada's strong commitment to addressing climate change and to working with the international community in dealing with this global problem. To support its ratification decision, the Government of Canada released the *Climate Change Plan for Canada*, which is a road map for Canada to follow in order to achieve its Kyoto target. The Plan established that measures underway at the time of its release were expected to achieve 80 Mt of emissions reductions. These included carbon sinks of 30 Mt from existing forestry and agricultural practices. As a second step, the Plan highlighted measures to reduce emissions by an additional 100 Mt. At the heart of this second step are the negotiations of covenants with large final emitters to reduce industrial emissions by 55 Mt. Also proposed was a series of measures targeted at sectors non-covered under the covenant approach. As a third step, the Plan suggests further emissions reductions of 60 Mt from various sources such as new technologies and initiatives by provincial and territorial governments.

NOTABLE ENERGY DEVELOPMENTS

ENERGY AND ENVIRONMENT

The federal budget of February 2003 announced new climate change investments of CAN$2 billion over five years, of which CAN$300 million was allocated to specific programmes in the budget itself and another CAN$1 billion was allocated by the government in August. Negotiations of covenants with large final emitters also proceeded in 2003. Participants would have access to a domestic emissions trading system with access to international permits and domestic offsets. The federal government's 2003 budget funds the following new climate change measures:

- Support for climate science research through additional funding provided to the Canadian Foundation for Climate and Atmospheric Sciences;
- Support for the demonstration of new technology through additional funding provided to Sustainable Development Technology Canada;
- A new federal Technology and Innovation Initiative, supporting federal research and development in five priority areas: cleaner fossil fuels, advanced end-use efficiency technology, decentralized energy production, biofuels, and the hydrogen economy;
- Expanded programmes to encourage Canadians to make their homes more energy efficient, and make environmentally-friendly transportation choices;

- Expanded programmes to encourage businesses and institutions to reduce emissions using available technologies in areas such as the buildings and transportation sectors;
- Partnerships with provinces and territories on cost-effective emission reduction initiatives;
- Sustained efforts by the Government of Canada to reduce federal emissions; and
- Assisting aboriginal and northern communities in emission reductions.

In October 2003, the Government of Canada launched several additional climate-change programmes including a public investment to extend Canadian leadership in the emerging hydrogen economy. Industry was invited to submit proposals for contributions towards the construction of new ethanol plants under the new CAN$100 million Ethanol Expansion Program. A financial incentive for energy-efficiency retrofits of houses was initiated as well.

Cooperative agreements on climate change have recently been signed with two provinces and territories, and other such agreements are expected in coming months. Also, on 6 November, the Government of Canada signed a memorandum of understanding with the pulp and paper industry, the first such agreement concluded in the context of negotiating covenants with large final emitters.

POWER BLACKOUT IN ONTARIO

On 14 August 2003, a cascading power outage caused the largest blackout in history, affecting some 50 million people and nearly 62 GW of generating capacity in Ontario and the northeastern United States. In some parts of Ontario, rolling blackouts continued for ten days before full power was restored and the entire system was back to normal. In response to the blackout, Prime Minister Jean Chrétien and President George Bush established the Joint Canada - U.S. Power System Outage Task Force to identify the causes of the outage and recommend actions to prevent future outages.

The Power System Outage Task Force issued an interim report in November 2003 on the causes of the blackout. It assesses the conditions on the transmission grid that contributed to the blackout, outlines the physical causes of the outage, and discusses events and conditions that allowed the blackout to spread. The report assigns primary responsibility for the blackout to the actions of one utility company and one independent system operator, noting specific ways in which they violated operating procedures established by the North American Electric Reliability Council. Views on the interim report will be solicited at public consultations with stakeholders in three cities (one in Canada and two in the United States). In early 2004, the Task Force will issue a final report with recommendations on actions to reduce the likelihood of future blackouts and make the electric power infrastructure more reliable.

In addition, Canadian energy ministers established a Federal-Provincial-Territorial Electricity Working Group in September 2003. Objectives of this group are to exchange information on the August power outage, work towards reducing constraints on investment in electricity infrastructure and assess initiatives to implement mandatory electricity reliability standards.

RENEWABLE ENERGY

In 2002, the $260 million *Wind Power Production Incentive* was launched to assist in the development of wind energy projects across Canada. In 2003, Canada's first urban wind turbine was installed in Toronto, and its largest wind farm to date, with CAN$100 million invested in 114 turbines, opened in Alberta. Saskatchewan, Quebec and Prince Edward Island also have wind farms.

ELECTRICITY MARKET REFORM

In British Columbia, the vertically-integrated BC Hydro and Power Authority is to have its transmission assets unbundled into a new BC Hydro Transmission Corporation by 2004, according to a new energy policy announced in November 2002. This should reinforce the ability of competing electricity generators to obtain fair access to the provincial transmission grid. But the energy policy also provides that consumers should continue to share the rents from existing hydro generating assets, which are low in cost because they are almost completely depreciated, through a ten-year extendable "heritage contract" on the output from these assets to ensure low electricity rates. In addition, the policy ended a seven-year rate freeze in 2003 and established that rates would once again be regulated by the BC Utilities Commission. The policy envision some rate increases to attract investment in new generation and transmission facilities, but would limit the increases through shared rents from hydro assets, competition among generators, and performance-based regulation.

In New Brunswick, competition in wholesale and retail power markets was introduced in April 2003. In the wholesale market, competing generators can obtain access to the transmission grid according to an open access transmission tariff filed by New Brunswick Power in June 2002. In the retail market, 40 large industrial customers will be allowed to choose their power suppliers.

Nova Scotia announced plans for a competitive electricity market in December 2001 and set up an Electricity Market Governance Committee in May 2002 to implement them. Under these plans, utilities and independent generators would be able to access the transmission system on equal terms. Competition is to be introduced in stages, starting with the province's six municipal utilities.

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CHILE

INTRODUCTION

Chile is one of the two APEC economies in South America. Located in the southern South America, it is bordered by the South Pacific Ocean between Argentina and Peru, and stretches along a coastline of 6,435 km. It's area covers nearly 757,000 square kilometres. Most of its 15.6 million population (as of July 2003 estimates) live in urban areas, with nearly one-third residing in Santiago, the capital. Chile is a major producer and exporter of copper.

Chile's GDP in 2001 reached US$133.5 billion, and US$8,669 per capita, both in terms of purchasing power parity, PPP, in 1995 US$. The economy grew at an average annual rate of 5 percent from 1990 to 2001. The economy's heavy dependence on exports, the Asian financial crisis in 1997, and the sluggish global economy in 2001, have all contributed to the equally sluggish economic growth. In 2002, Chile signed free trade agreements with Korea and the European Union, its other trading partner. It expects to sign similar agreements with Japan and the United States soon.

Chile has very limited indigenous energy resources and has to rely on imports to meet all of its needs. In 2003, its energy reserves consisted of 23.9 MCM of oil, 98 MCM of natural gas and 1,811 Mt of coal. In 2001, roughly two-fifths of its total primary energy supply was produced indigenously.

Table 7 Key data and economic profile (2001)

Key data		Energy reserves*	
Area (sq. km)	757 000	Oil (MCM) - Proven	23.9
Population (million)	15.40	Gas (BCM)	98
GDP Billion US$ (1995 US$ at PPP)	133.52	Coal (Mt)	1,811
GDP per capita (1995 US$ at PPP)	8,669		

Source: Energy Data and Modelling Center, IEEJ. * 2003 figures from Energy Information Administration, USA.

ENERGY DEMAND AND SUPPLY

PRIMARY ENERGY SUPPLY

In the last two decades, Chile's total primary energy supply (TPES) grew on an average of 4 percent per annum and reached 24,921 ktoe in 2001, approximately 38 percent from crude oil, 20 percent from natural gas, 11 percent from coal and 30 percent from other sources, mainly biomass and hydropower. In 2001, natural gas and renewable energy supply, included hydropower, shared around 25 percent each of the TPES, or 50 percent for both together. Meanwhile, coal and oil declined for 22.1 percent and 2.5 percent respectively. Although an introduction of natural gas from Argentina in 1997 has led a change in Chilean TPES mix, more gas use, oil remains a major energy source, 41 percent of share in 2001 compared to 44 percent in 1990. However this made a reduction in a use of coal, with a drop of its share from 18 percent in 1990 to 9 percent in 2001.

Chile's energy-import dependency had been increased for many years. In 1980, approximately 64 percent of TPES was contributed by indigenous production and 36 percent net imports, but in 2001, this proportion was reversed to be 56 percent from the imports and the rest from indigenous production. The change is caused mainly by an increase in gas and oil imports even her more use in domestic renewable, such as hydropower and biomass.

For the past two decades, imports have increased for several reasons. Due to dwindle of oil reserve, crude oil production peaked in 1982 at 32 percent of domestic supply, but turned to decline and produced only 3 percent of total oil supply in 2001. A lack of competitiveness of domestic coal industry has led an increase in coal imports. Domestic coal production was accounted for only 16 percent of Chilean consumption in 2001, down from nearly 70 percent in 1980. The gas market has been restructuring by the imports from Argentina to the most populated regions in north and central of Chile since 1997. Previously, due to infrastructure constraints, gas was only available in the south.

Empresa Nacional del Petróleo (ENAP), a state-owned enterprise, is a major oil producer and refinery in Chile. Due to dwindle of domestic resources, ENAP is increasing its exploration and production in 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 of petroleum products works under 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 2001, Chile's power generation was 42,532 GWh. During the period 1980 to 2001, the generation increased consistently around 6.3 percent per annum. Hydropower has been accounted for a major installed capacity. However, thermal is getting more significant, and in 2001, the thermal installed capacity was 20,852 GWh, 49 percent of the total installed capacity. The introduction of natural gas from Argentina has boosted up combined cycle plants. Thermal relies mainly on natural gas and coal, 60 and 34 percent respectively, but there is some from fuel oil, biomass, and other fuels (6 percent) as well. The use of petroleum coke (petcoke) is allowed in some plants, but under restrictions of environmental control.

Table 8 Energy supply & consumption for 2001

Primary Energy Supply (ktoe)		Final Energy Consumption (ktoe)		Power Generation (GWh)	
Indigenous Production	11,049	Industry Sector	6,083	Total	42,532
Net Imports & Other	13,871	Transport Sector	5,429	Thermal	20,852
Total PES	24,921	Other Sectors	7,792	Hydro	21,680
Coal	2,414	Total FEC	19,304	Nuclear	-
Oil	10,128	Coal	956	Others	-
Gas	6,151	Oil	9,913		
Others	6,228	Gas	1,245		
		Electricity & Others	7,189		

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 4.1 percent from 1980 to 2001 and reached 19,304 ktoe in 2001, but year-on-year growth rate in 2001 declined 1.7 percent. The main energy-consuming sectors were transport (32 percent) and industry (28 percent) with residential, commercial and public sectors consuming 40 percent. By energy source, oil products was accounted for 51 percent of final consumption, electricity and "other" sources 37 percent, gas 7 percent, and coal 5 percent.

Chile is the world's largest copper producer and expected to grow to 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 development in copper industry alone can make energy demand jump sharply. A change in production methods, particularly penetration of hydro-metallurgical processes, has led an increase in electricity consumption of the industry.

Energy consumption in the industrial sector is concentrated highly in three industries, accounted for half of it. The main one is copper industry, which leads near 25 percent of industrial energy consumption or 9 percent of TFEC, follows by paper&pulp and iron&steel industries, with 17 percent and 8 percent respectively. However, in the 1990's, most of the 6.6 percent annual growth in industrial energy use was driven by non-energy-intensive industries, which demand grew 9.1 percent yearly. For the total industrial energy consumption by fuel type, 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 replacing for petroleum products, especially heavy fuel oil and coal in the industrial sector due to the introduction of Argentinean gas in northern and central Chile.

Transportation has recently been the fastest growth of end-use sector, with an increase on an average of 4.2 percent per annum for a decade. In 2001, road transport was responsible for 76 percent of energy consumption in transport. Petroleum products were accounted for 99.5 percent, electricity 0.3 percent and natural gas 0.2 percent.

In the residential, commercial and public sectors, growth in energy use is similar to transportation, on an average of 4.3 percent per annum between 1990 and 2001. The residential sector accounted for 30 percent of energy consumption in 2001. In 2001, biomass (mostly firewood) was the most important fuel in this sector, accounted for 51 percent, following by 23 percent for petroleum products and 18 percent for electricity. Furthermore, the 7 percent share of natural gas is expected to increase due to imported gas from Argentina.

POLICY OVERVIEW

Chile's energy sector is mostly private. Energy policy decisions are shared responsibilities of the National Energy Commission (NEC), the Ministry of the Economy, the Superintendency of Electricity and Fuels, and the Chilean Commission on Nuclear Energy.

As early as the 1990s, the economy has diversified its energy mix from hydroelectric power towards natural gas fired electric generation. But after a severe drought in 1998-1999 (which resulted in massive blackouts), the economy changed its energy policy. In April 2002, CNE has envisioned 10 new gas fired power plants and one hydropower plant in 2010. This was however halted as the supply of natural gas to the economy was temporarily disrupted, due to some social problems from its gas supplier, Argentina. Chile therefore has to rethink its long-term energy strategies, of which requiring new natural gas-fired power plants to be capable of using fuel oil.

Mitigating the threat to the environment, mainly air pollution from vehicles and industrial emissions, water pollution from untreated industrial sewage, deforestation and soil erosion, has been one of Chile's primary concerns. Mitigating these threats would mean increasing use of alternative fuels in the economy's industrial and energy sectors. Therefore, reliance to natural gas and hydro for power generation would keep the total carbon emissions at a minimum.

Chile's National Energy Commission (CNE) has established some policy guidelines to promote sustainable development in energy:

- Policies should be geared towards the promotion of energy efficiency;
- Energy development must ensure the protection of the environment;
- Private investments should be the main source of capital for energy expansion; and
- Social equity. Alleviation of Poverty through employment in energy development and provision of basic energy services. Promotion of rural electrification using NRE in remote, inaccessible areas.

NOTABLE ENERGY DEVELOPMENTS

Chile has recently released its electric power capacity expansion plan in April 2002. In the next ten years, the plan foresees the development of additional 10 new combined cycle-gas fired power generation plants and some hydroelectric facilities.

The new electricity law, Law No. 19,613 (1999) gives the Superintendency of Electricity and Fuels the authority to monitor power companies and impose fines for failure to comply with contractual supply obligations to distributors and large customers. Article 99bis requires power generation companies to guarantee the supply of electricity in all circumstances, including drought. Article 88, on the other hand, has required all generators to sell electricity to distributors even without a contract.

A new electricity bill was introduced to Chile's Congress that would seek to regulate electric power transmission fees. However, no agreements were reached because of differing opinions on how much of the transmission fees the generators and consumers should pay. Another subject of debate is the new interconnection between the SIC and SING power grids, as well as the proposed connection to Argentina.

UPSTREAM ENERGY DEVELOPMENT

In February 2003, Empresa Nacional de Petroleo (ENAP), Chile's national oil company and operator of Magallanes basin, had received approval from the Ministry of Economy to invest $264 million into projects. The investments will cover much of the economy's refinery modernisation program and its oil exploration and production operations outside of Chile. Sipetrol, ENAP's foreign exploration subsidiary, will be responsible for all its international activities (e.g. Argentina, Colombia, Ecuador and Egypt).

DOWNSTREAM DEVELOPMENT

ENAP controls all three refineries of Chile. Petrox SA, the largest of the facilities, has an approximate crude throughput capacity of about 100,640 bbl/d. Crude is supplied from Argentia through the Trasandino pipeline which extends through Argentina's Neuquen Basin.

The second largest refinery, Refineria de Petroleo Concon, has a capacity of about 94,350 bbl/d. In August 2003, Petrobras (Brazil's state oil company) has announced that negotiations are underway with ENAP over a potential participating interest of $300 million, for the expansion of the Concon refinery.

Chile is fast becoming a highly dependent natural gas importer. In 2001, the economy has imported about 188 Bcf of natural gas, mostly coming from Argentina. Since 1997, four natural gas pipelines have been built which transport natural gas from Argentina. These lines are: GasAtacama, Norandino, GasAndes, and the Pacifico. These lines supply the economy's urban centers, mines and power generators. The latter is the largest consumer of natural gas which is projected to take up half of the economy's total supply by 2011.

In 2003, the GasAndes pipeline was extended 46 miles south from Santiago to a smelter in Caletones. The pipeline, completed in early 1997, delivers natural gas from Argentina's Neuquen basin to three 370 MW power plants around the economy's capital, Santiago. The pipeline is controlled by TotalFinalElf, and in cooperation with Compania General de Combustibles, AES, and Metrogas.

POWER PROJECTS

The economy's electricity demand is expected to grow by 6 percent annually in the next ten or twenty years. Power companies therefore have been developing several new projects:

- Endesa (Spain) is developing a 570 MW Ralco hydroelectric plant in the Bio Bio River, 310 miles south of Santiago. Completion is expected by 2003, but will most like being delayed because of some right of way and relocation problems;
- AESGener is proposing the construction of a 740 MW gas-fired plant in Totihue in central Chile but was later postponed due to some regulatory approval problems. Endesa's 570 MW Ralco hydro project and Colbun's expansion of its existing Nehuenco from 380 MW to 800 MW continues however and is expected to be completed in 2004; and
- Colbun has announced in July 2003 that it also plans to invest $1 billion to expand its company's generation capacity by 2010.

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CHINA

INTRODUCTION

China is the fourth largest economy in the world, next to Russia, Canada and the United States. It is located in East Asia, borders the East China Sea, Korea Bay, South China Sea and lies between North Korea and Viet Nam. Its population of 1.3 billion is roughly one fifth of the world's population. Its diverse landscape consists mainly of mountains, deserts, and river basins and covers around 9.6 million square kilometres.

Currently, China is the world's second largest energy consumer (next to the United States) and the third largest energy producer (after the United States and Russia). However, its per capita primary energy consumption (at 0.6 toe) is by far lower than in many developed economies and the world's 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. GDP per capita is still quite low, at US$ 3,778 (1995 US$ at PPP) in 2001.

China is rich in energy resources, particularly coal. It is the largest producer and consumer of coal in the world, as well as the fifth largest producer and second largest consumer of oil in 2002 (according to the data from BP Statistical Review). However, after a long history of being a net oil exporter, China finally 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 2,910 MCM[1] and proven natural gas reserves of 1,510 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 (2001)

Key data		**Energy reserves***	
Area (sq. km)	9,600,000	Oil (MCM)	2,910
Population (million)	1,271.85	Gas (BCM)	1,510
GDP, Billion US$ (1995 US$ at PPP)	4,804.81	Coal (Gt) - Recoverable	114.5
GDP per capita (1995 US$ at PPP)	3,778		

Sources: Energy Data and Modelling Center, IEEJ. * Proved reserves, end of 2002, *BP Statistical Review.*

ENERGY DEMAND AND SUPPLY

PRIMARY ENERGY SUPPLY

After two decades of continuous growth, the total primary energy supply (TPES) in China peaked at 847,829 ktoe in 1996 and declined to 790,018 ktoe in 2001. The recent decline was mainly due to the slower growth and structural changes in its economy. Of the total TPES, coal

[1] BP revised the oil reserve data in 2002. This data is much less that it was a year before.

accounts for 65 percent, oil for 28 percent, and natural gas for 3 percent, while hydropower, nuclear power and other sources account for the remaining 4 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 for several years and started to recover from 2001. Coal consumption in 2002 reached 97 percent of its peak to 663.4 mtoe[2].

In 2002, imports provided around a third of crude oil and petroleum product requirements. China's oil output in 2002 was 168.9 million tons, a slight increase from its previous years' output. 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 still quite small, even in the last few years, Chinese authorities have begun to promote gas use in the building sector and industrial sector, as well as for power generation. China's "West to East" pipeline project has made great progress and expects its first LNG receiving terminal to be built in 2003 in the Gungdong Province.

Table 10 Energy supply & consumption for 2001

Primary Energy Supply (ktoe)		Final Energy Consumption (ktoe)		Power Generation (GWh)	
Indigenous Production	763,120	Industry Sector	305,408	Total	1,471,657
Net Imports & Other	26,898	Transport Sector	61,015	Thermal	1,176,753
Total PES	790,018	Other Sectors	202,538	Hydro	277,432
Coal	515,473	Total FEC	568,961	Nuclear	17,472
Oil	219,295	Coal	237,619	Others	-
Gas	25,413	Oil	186,286		
Others	29,837	Gas	27,285		
		Electricity & Others	117,772		

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 353 GW by 2002. In 2002, electricity generation grew by 10.5 percent to 1,640 TWh[3]. Thermal plants, mostly coal-fired, accounted for 82 percent of generation, same as the year of 2000, while hydropower generation accounted for 16.5 percent and nuclear power for 1.5 percent with growth rate of 4 and 43 percent respectively. By the end of 2002, the total installed hydropower capacity has reached 85 GW, and has accounted for 24 percent of the total generating capacity. Nuclear power installation capacity likewise reached 3.7 GW, an increase of 76 percent from 2001.

FINAL ENERGY CONSUMPTION

Final energy consumption in China reached 568,961 ktoe in 2001. Industry was the largest user accounting for 54 percent of energy consumption. Transportation accounted for 11 percent of energy use and other sectors 36 percent. In terms of fuels, coal (42 percent) still was the most

[2] BP Statistical Review

[3] China resource conservation and environmental protection network, http://www.drccu.gov.cn

important despite its 1 percent reduction even it reduce in 2000, followed by oil (33 percent), electricity, heat and other fuel (19 percent), and gas (5 percent).

POLICY OVERVIEW

China is making efforts to achieve its targets contained in its Tenth Five-Year Plan. The economy has kept growing very fast by enhancing investment and absorbing overseas capital. In 2002, total investment reached US$508 billion, accounting for 39.4 percent of its GDP, the highest since 1996. Energy, especially electricity production and consumption grew very rapidly after a brief period of power surplus in some regions. Power shortages were however experienced again during peak-load season nationwide. 19 provinces and Municipalities have adopted 'blackout measures' to limit power consumption. As a result only northwest, northeast and Shangdong grid were kept at a balance. Local governments are planning to build more power plants in the next few years. Coal and crude oil production in 2002 has reached or exceeded the "special energy development plan" targets of the Tenth Five-Year Plan.

FURTHER COAL PRICING REFORM

Coal is traditionally subsidised heavily as a basic energy source. In 1992, 6 billion yuan (about 720 million US dollars) went to 94 state-owned coal-mining enterprises. In 1995, the price of coal was deregulated in principle, but coal remained subsidised in one of its most import uses - power production. The subsidised coal price made many power plants artificially profitable - so some inefficient power plants had to be shut down by government.

In 2002, coal prices were deregulated for the power sector as well. The price has been quite stable, increasing only 8 percent between 2001 and 2003.

But since electricity prices were regulated, the high coal prices had squeezed power producers, who are unwilling to operate at lower revenues. At the national coal trade conference, the volume of new coal contracts sighed by power producers for 2003 was only 40 percent of what had been expected. This exacerbated the power shortage in 2003's summer.

ENERGY SECURITY

To ensure adequate supply of energy (especially oil), besides measuring the degree of conservation measures and oil substitution, and accelerating the development of domestic oil resources, promoting oil exploitation overseas to Chinese oil companies is an important policy from government and a business strategy for oil companies. Unfortunately, the implementation strategy is not going very well and Chinese oil companies have lost its chances to internationalise. The war on Iraq hastened the procedure of establishing oil stockpile. Oil storage facilities are under construction. The total investment of US$ 100 billion will be arranged in the next 20 years to build oil the stockpile system. It is targeted that until the year 2020, China will have 35-60 million tons of oil for stockpile. Meanwhile, Xingjiang, Chuanyu, Shangnning and Qinghai oil fields are chosen as un-mined backup reserves.

WORK SAFETY LAW

The Law of the People's Republic of China on Work Safety went into effect on November 1, 2002. It requests all production and business units to redouble their efforts to ensure work safety by setting up and improving the responsibility system for work safety and improving the conditions for it to guarantee work safety.

The recent increase in serious accidents at coalmines, as well as other production and traffic accidents have raised concerns from the highest government officials. The government therefore has resolved to close those coalmines which cannot meet the national standards or industrial specifications for work safety, formulated in accordance with law. The move however will result in two consequences: a reduction in coal production capacity and supply in short term, and bigger investment requirement to improve coalmine equipment.

IMPROVING ENERGY EFFICIENCY

Over the last two decades, China has greatly reduced the energy intensity of its economy through energy conservation measures and economic structure optimisation, from 0.568 toe per thousand 1995 US$ of GDP (PPP) in 1980 to 0.164 toe per thousand 1995 US$ of GDP (PPP) in 2001.

Voluntary Agreements (VAs) are considered as a policy for increasing industry energy efficiency in China. Through a pilot project with steel industry, China plans to develop a framework to promote VAs utilisation including methodology for assessment of energy efficiency improvement potentials, supporting policies and methodology for target setting. The local government will provide the following policies to support the pilot project:

- Give priority consideration to the pilot enterprises under existing preferential policies;
- Coordinate the provision of guarantees by the provincial guarantee company for loans and other financial activities required for energy-efficiency projects at the pilot enterprises;
- Use various media to publicise the energy-conservation achievements and contributions of the pilot enterprises; and
- Organise intermediary organisations to provide the pilot enterprises with policy, technical, management, and other advice and services.

ENVIRONMENTAL PROTECTION

A new version of the regulation for charging pollutant emissions was published by the State Council in January and will be effective in July 2003. It has several differences comparing to the old one as shown in the following:

- All entries and individual business should pay emission fee;
- Charge to waste water, waste gas, noise over the standard, solid waste and dangerous materials;
- Emission fee will be used for pollution preventing, new technology and process developing, demonstrating and utilising. This fee can't be used by environmental protection agencies;
- Collecting emission fee will be listed in the fiscal budget and managed as a special fund;
- More clear and transparent requirements on supervision, monitoring and auditing to the emission fee management; and
- In the case of the SO_2 emission fee for example, under the new regulations, all emitters (nationwide) are required to pay a fixed fee of 0.63 yuan/kg-SO_2 for all its emissions. This will have an impact on the power industry as this would increase several times the SO_2 emission fees paid by a conventional coal-fired power plant. In the old version, it is only the emitters in the "Two-controlling areas" (acid rain and SO_2 controlling areas) that are required to pay for their emissions, in excess of the national standards and at a price of 0.2 yuan/kg-SO_2.

ENERGY BUREAU OF NATIONAL DEVELOPMENT AND REFORME COMMISSSION

In April 2003, during the new round of administration reform, the former State Development and planning Commission (SDPC) was renamed: National Development and Reform Commission (NDRC) The Energy Bureau (which now includes the National Oil Stockpile Office) was established under NDRC with the following responsibilities:

- Research on energy development situation and make energy development strategy and key policies;
- Make energy development planning and suggestions on energy industry reform;
- Implement management of oil, natural gas, coal, electricity and other sort of energy;
- Manage national oil stockpile; and
- Make policies and measures on energy conservation and new energy development.

NOTABLE ENERGY DEVELOPMENTS

IMPORT LNG PROJECT

Besides domestic resource development, importing LNG is another way to increase natural gas utilisation and improve primary energy mix. The first LNG receiving terminal has started to build in Guangdong Province. It will receive 4-billion cubic meters of natural gas annually from Australia in 2005. The second phase of this project will be finished in 2008 and will import 4.2-billion cubic meters of natural gas from Australia and South China Sea. Another LNG project in Fujian Province is being planned which will import around 3.5-billion cubic meters of natural gas per year from Indonesia.

ELECTRICITY GENERATING FROM THREE GORGES

After a decade of construction, the largest hydroelectric facility in the world-Three Gorges project, has generated its first kilowatt-hour electricity in June 2003. It is expected to produce about 5.5 TWh of electricity this year, supplying electricity to both east and central China. The capacity of Phase I will reach 18GW with an output of 84TWh. The total capacity for the whole Three Gorges project will be around 40 GW, producing almost one tenth of power nationwide.

RESTRUCTURING THE ELECTRIC POWER INDUSTRY

The restructuring of the electric power industry has made real progress in 2003 after a long period of debate and research. The generation and transmission are separated. Five generating companies were set up based on the former State Power Cooperation. The large hydropower companies and those power companies listed on domestic stock exchange are requested to join the five companies. Besides the five power companies; Huaneng, Datang, Huadian, Longyuan and Power Investment, there are 45 other local power generating companies, rural hydropower companies, nuclear power companies, hydropower companies which belong to hydroelectric facilities and IPPs not involved in the restructuring Two gird companies were also set up; the State Power Gird Company and South Grid Company. State Power Gird Company is divided into five regional grid companies: Eastern China, Central China, Northwest (based on the branch companies) and North China (based on one son company plus gird in Inter Mongolia). South Grid Company covered the region of Guangdong, Hainan, Yunnan, Guizhou and Guangxi Province.

Along with the restructuring of the State Power Cooperation, a newly established organisation called Power Regulatory Commission was set up which is responsible for regulating the power sector. It is an administrative body authorised directly by the State Council to conduct supervision and regulation of the power industry in accordance with the law. Its major responsibilities are:

- To conduct supervision and regulation of the national power, establish a centralised supervisory system, and assume direct leadership over branch bodies;
- To organise the drafting of laws and regulations for power industry. To study and formulate the principles, policies and rules related to power industry and power market;
- Engage in making national power development planning, draft power market developing planning and regional power market schedules. Authorise power market operating mode and establishment of power trade organisation's plan;
- Supervision of power market operation, regulate power market order, keep fair competition; supervision of power transmission, distribution and other non-competition business in power sector;
- To involve in making and supervision of standards related to power industry. Issue and manage the certifications for power business, co-ordinate environmental protection organisations to supervise the implementation of environmental protection policies, regulations and standards;
- Submit suggestions on power tariff changing to the pricing authorities based on the market situation; supervising electricity price and all other related charging standards;
- Investigate activities violating laws and regulations on power market and power enterprises, deal with the conflicts of power market;
- Supervision of implementation of nationwide power service policy, study and raise the suggestions on improving services; in charge of power market statistics and information issuance;
- To exercise power industry reform plan based on the State Council's plan, raise the suggestions to deepen reform; and
- Any other duties as commissioned by the State Council.

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HONG KONG, CHINA

INTRODUCTION

Hong Kong, China is a city-economy of some 6.7 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, financial and other service activities. Hong Kong, China is a principal service centre not only in the Asia-Pacific region but also worldwide.

Table 11 Key data and economic profile (2001)

Key data		Energy reserves	
Area (sq. km)	1,097	Oil (MCM)	-
Population (million)	6.73	Gas (BCM)	-
GDP Billion US$ (1995 US$ at PPP)	158.51	Coal (Mt)	-
GDP per capita (1995 US$ at PPP)	23,570		

Source: Energy Data and Modelling Centre, IEEJ.

ENERGY DEMAND AND SUPPLY

PRIMARY ENERGY SUPPLY

In 2001, total primary energy supply in Hong Kong, China was 15,150 ktoe. Of this total, 52 percent was oil, 30 percent coal and 13 percent gas. Electricity imports from China accounted for the remaining 5 percent. Hong Kong, China has no domestic energy reserves or petroleum refineries and imports all of its primary energy needs, though it generates some electricity. In 1995, Hong Kong, China 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 2001. 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 10,904 ktoe in 2001. The bulk of energy was used in the transportation sector (54 percent), followed by the residential/commercial sector (32 percent) and the industrial sector (14 percent). With the dominance of transport, the most important end use fuel was petroleum, accounting for 65 percent of energy use. Electricity made up 29 percent of end-use consumption, while gas accounted for only 5 percent.

Table 12 Energy supply & consumption for 2001

Primary Energy Supply (ktoe)		Final Energy Consumption (ktoe)		Power Generation* (GWh)	
Indigenous Production	-	Industry Sector	1,535	Total*	32,429
Net Imports & Other	15,150	Transport Sector	5,889	Thermal	32,429
Total PES	15,150	Other Sectors	3,480	Hydro	-
Coal	4,556	Total FEC	10,904	Nuclear	-
Oil	7,814	Coal	4	Others	-
Gas	2,025	Oil	7,125		
Others	754	Gas	571		
		Electricity & Others	3,204		

Source: Energy Data and Modelling Centre, 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), on the other hand, is supplied by oil companies. In energy terms, town gas accounted for 73 percent of gas use in these sectors in 2001. The first gas-fired power plant was opened in Hong Kong, China 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's 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 ENERGY 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 schemes cover lighting, air-conditioning, electrical and lift & escalator installations. The government has launched a consultancy study on performance-based BECs in mid-April 2003. The study uses a total-energy-budget approach and aims to provide an alternative path for compliance with the existing codes.

As end of February 2003, the government has issued labels for more than 1,600 appliance models including refrigerators, room coolers, washing machines, electric clothes dryers, compact fluorescent lamps, electric storage water heaters, photocopiers, electric rice-cookers, multifunction devices, dehumidifiers and laser printers under voluntary energy efficiency labelling schemes.

A voluntary energy efficiency-labelling scheme was launched for petrol Passanger Cars in February 2002 to raise public awareness in the energy efficiency of vehicles. New schemes for televisions and LCD monitors are planned to be launched in late 2003.

ENERGY AUDIT PROGRAMME

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 energy-consuming buildings. With the help of these audits, the top electricity consuming Government departments have conducted various energy saving measures and successfully reduced their annual electricity consumption by some 4.5 percent. Pilot test on energy Management Opportunities (EMO) using innovative energy efficiency equipment related to lighting, air-conditioning and vertical transportation have also been carried out to achieve energy savings in government buildings since 1999. The tests have been very successful, with substantial energy savings achieved. The Government has also published reports and application guidelines to promulgate the use of the EMOs. The studies include application of T5 lamps, evaporative cooling systems, heat pumps and others.

ENERGY END-USE DATABASE

The government has continuously maintained and updated the energy end-use database. The database provides useful insight into energy consumption patterns of different sectors, sub-sectors and the end uses in Hong Kong. The Transport energy Consumption Survey was commissioned in mid March 2002 to develop energy use intensities for public non-franchised buses, private light buses, medium goods vehicles (MGV) tractors, MGV non-tractors and heavy goods vehicles in the transport sector. The study will be completed by mid 2003. A basic data set from the database is made available for public access from www.emsd.gov.hk. The year 2000 basic data set was published in December 2002. A factorisation study aiming to identify the contributions of various factors affecting historical energy use is being conducted.

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 LPG or electricity. The program to replace all 18,000 diesel taxis in the Territory with LPG taxis has now been reached 95 percent (17,157) taxis). The end of 2005 will fuel all taxis by LPG. 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. EMSD will continue to play its role in the gas safety and advisory aspect.

RENEWABLE AND CLEAN ENERGY

The government commissioned a consultancy study in November 2001 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 first stage of this study has already been completed and has already identified a number of new and renewable 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 in end 2002. Plans have already been made to install about 650 kW of photovoltaic panels in eleven government projects in coming three years. The whole study will be completed in early 2004.

CONSULTANCY STUDIES ON WIDER USE OF:

WATER-COOLED AIR CONDITIONING SYSTEM (WACS)

The government is conducting three consultancy studies in order to recognise the energy saving potential of WACS. One is on the territory-wide implementation of WACS and the other two are on the implementation of district cooling system in a new development area and an existing developed area. The studies are expected to be completed in 2003.

ENERGY CONSUMPTION INDICATORS AND BENCHMARKS

The consultancy study on the development of energy consumption indicators and benchmarks has been completed. The study covered private offices and commercial outlets in the commercial sector, and private cars and light goods vehicles in the transport sectors. The study has established energy consumption indicators and benchmarks to enable targeted groups to set its own improvement targets. A benchmarks tool will also be made available to enable individual operators to benchmark their energy consumption with others in the same group. The study will also identify and implement improvement measures. The result of the study will also identify and implement improvement measures. The result of the study together with benchmarking tool is available for download from the EMSD website.

The study is now being extended to cover hospitals, polyclinics, universities, schools and hotels, as well as medium and heavy goods vehicles in the transport sectors. The extended study is scheduled to be completed in 2003.

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INDONESIA

INTRODUCTION

Indonesia is an archipelago comprised of 17,508 large and small islands near the equator, with a total land area of about 2 million square kilometres. The population in 2001 is about 209 million, the majority of whom reside in Java, one of the five main islands.

In 2001, real gross domestic product (GDP) was US$572.44 billion and per capita GDP was about US$2,739 (both in 1995 US$ at PPP). Manufacturing was the major contributor, accounting to 26 percent of the real GDP, while agriculture, livestock, forestry and fishery, including trade, hotel and restaurant, contributed 16 percent. Mining and quarrying contribution was about 14 percent, transport and communication 5.4 percent, financial ownership & business services 6.2 percent, services 9.5 percent, construction 5.6 percent and the least, electricity, gas and water supply at 1 percent.

Economic growth slid to 3.1 percent in 2001 from 4.8 percent in 2000 because of the global economic slowdown, which reduced the demand for the economy's exports. However, despite the tragic Bali bombings in October 2002, Indonesia managed to attain a slight improvement in its economy, growing by an average of 3.7 percent in 2001. Mining activities, especially of petroleum and tin, have expanded since 1970. Fossil energy resources, such as oil, natural gas and coal, play important roles in the economy as industrial raw material and foreign exchange earners. In 2001, Indonesia possessed oil reserves of around 795 MCM, natural gas reserves of around 2,620 BCM and coal reserves of 5,220 Mt.

Table 13 Key data and economic profile (2001)

Key data		Energy reserves*	
Area (sq. km)	1,937,179	Oil (MCM)	795
Population (million)	208.98	Gas (BCM)	2,620
GDP Billion US$ (1995 US$ at PPP)	572.44	Coal (Mt)	5,370
GDP per capita (1995 US$ at PPP)	2,739		

Source: Energy Data and Modelling Centre, IEEJ.

* Proved reserves at the end of 2001 from the BP Statistical Review, except coal at the end of 2002

ENERGY DEMAND AND SUPPLY

PRIMARY ENERGY SUPPLY

In 2001, total primary energy supply was 94,213 ktoe. Of this total, 52 percent was oil, 26 percent gas, 16 percent coal, 4 percent geothermal and 2 percent from hydropower. Indonesia is a net energy exporter, selling 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 Natuna Sea. During the last decade, crude oil production in Indonesia ranged between 1.3 and 1.4 million bbl/d. But as fields were continually developed and reserves deplete, crude oil production started to decline in the recent years. Thus, in 2003, Indonesia was only able to produce crude oil at a rate of 1.1 million bbl oil per day. Indonesia also produces around 131,000 bbl/d of natural gas liquids and lease condensate.

Besides relying on its domestic oil production, Indonesia also imports crude oil and refinery products to supply to its domestic needs. In 2001 Indonesia had imported 112.9 million barrels of crude oil and 89.6 million barrels of fuel oil. Although in the same year, Indonesia had exported 241.6 million barrels of crude oil and 81.9 million barrels of refinery products. In 2002, Indonesia the facto for the first time had became a "net oil importer". It has exported 185.9 million barrels of crude oil and 42 millions barrels of refinery products in 2002, while in the same year the economy imported 124 million barrels of crude oil and 106.9 million barrels of fuel oil. In total, Indonesia's net oil imports was 3 million barrels in 2002. Indonesia is however optimistic that it will immediately get out of its current status as a "net oil importer" as new oil resources are discovered and developed in the next few years.

In 2002, Indonesia's natural gas production reached around 79,089 ktoe, an increase of 5 percent from its 2001 production of 75,000 ktoe, or an increase of 30 percent from 2000 at 60,500 ktoe. 57 percent of the natural gas produced was used to supply the economy's domestic demand, while 43 percent was exported. Domestic gas utilisations were 31 percent for gas injection and fuel on the field, 42 percent for industry and electricity, 17 percent for fertiliser, 7 percent for city gas and 3 percent for refinery.

90 percent of the gas exported was LNG, 4 percent as LPG and 6 percent as piped gas. Of the exported LNG, around 69 percent went to Japan, 19 percent to Korea and 12 percent to Chinese Taipei. Despite however the availability of natural gas in Indonesia, its domestic use is relatively under-developed.

Indonesia has recoverable coal reserves of about 5,370 million tonnes, of which 59 percent are lignite, 27 percent sub-bituminous, 14 percent bituminous and less than 0.5 percent anthracite. In addition, a study has identified 10 more coal basins in Indonesia which contain 336 trillion cubic feet Coal Bed Methane (CBM). Indonesia's major coal reserves are located in the islands of Sumatra, and Kalimantan while some reserves are also found in West Java and Sulawesi. Indonesian coal generally has a heating value ranging between 5,000 - 7,000 kcal/kg, with low ash and sulphur levels. The sulphur content of Indonesia coal is below 1 percent.

In 2002, Indonesia has produced 104 million tonnes of coal and has exported most or about 70 percent of this production to Japan, South Korea and Chinese Taipei. Indonesia plans to double its coal production, viewing other economies in East Asia and India as markets of high potential.

Indonesia produced 100,526 GWh of electricity in 2001. It has an estimated installed generating capacity of 23.4 GW. Of its total electricity production, 83 percent came from thermal sources, 11 percent from hydropower and 6 percent from geothermal and other sources.

Table 14 Energy supply & consumption for 2001

Primary Energy Supply (ktoe)		**Final Energy Consumption (ktoe)**		**Power Generation (GWh)**	
Indigenous Production	168,460	Industry Sector	23,468	Total	100,526
Net Imports & Other	-74,247	Transport Sector	21,538	Thermal	83,965
Total PES	94,213	Other Sectors	20,855	Hydro	10,651
Coal	14,822	Total FEC	65,861	Nuclear	-
Oil	48,488	Coal	4,272	Others	5,910
Gas	24,905	Oil	43,974		
Others	5,998	Gas	10,345		
		Electricity & Others	7,269		

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 slightly declined to 65,861 ktoe in 2001 from 66,082 ktoe in 2000. The most important end use fuel was oil, accounting for 67 percent of consumption, followed by gas at 16 percent, electricity at 11 percent and coal at 6 percent. There was significant shifting on final energy consumption in 2001. Gas consumption grew by about 28 percent from 8.8089 ktoe in 2000 to 10,345 ktoe in 2001. Coal consumption increased by twice as much 2,053 ktoe in 2000 to 4,272 ktoe in 2001. Electricity consumption, on the other hand, dropped by 39 percent from 11,878 ktoe in 2000 to 7,269 ktoe in 2001. The changing consumption pattern has indicated a strong response to current and significant electricity tariff increases and the domestic gas utilisation program.

Increased tariff and subsidy removal also affected the sector's energy consumption. In 2000, industry surpassed transport as the largest consuming end-use sector, and accounted for 39 percent of final energy consumption. While transport sector and others sector (household and commercial) consumption have accounted to 32 percent and 29 percent respectively. Industrial sector's final energy consumption dropped by 7 percent from 25,170 ktoe in 2000 to 23,468 ktoe in 2001. In contrast, the others sector's (household and commercial) consumption grew by 7 percent from 19,459 ktoe in 2000 to 20,855 ktoe in 2001. The transportation sector's consumption remained constant. It seems that increases in energy prices has motivated the industries to implement energy saving and increase its energy efficiency, resulting to significant reduction in final energy consumption. The increase in energy use in the other sector (household and commercial sectors), on the other hand was mainly due to increased demand as a result of growth in the sector during the period.

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.

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;
- Protecting the environment; and
- 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 66 percent in 2001. 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 future price increases.

GREEN ENERGY INITIATIVE

Considering the potential of new and renewable energy sources such as wind, solar, hydro, geothermal and ocean power, Indonesia a launch green energy initiative in 2002. The initiative targeted the utilisation of renewable energy of about 78,500 MTOE by 2010. To reach the target, the generating companies will be required to have at least 5 percent of their installed capacity to utilise renewable energy sources. In addition, appropriate incentives and energy pricing will support the initiative.

ENERGY EFFICENCY

Not having been too successful in energy efficiency programs, which in fact started two decades ago, Indonesia has reformulated energy efficiency strategy. Standardisation, labelling, energy saving campaign are among the new programs intensified recently. The removal of energy subsidy entirely by 2004 could become an incentive for the successful implementation of the energy efficiency program target to reduce energy intensity by 1 percent every year.

NOTABLE RECENT ENERGY DEVELOPMENTS

OIL INDUSTRY

In 2002 and 2003, Indonesia has continued its oil industry reform process as well as inviting investors to conduct oil and gas exploration activities in order to increase the economy's oil reserves. The reform continued the development of several instruments to support the operationalisation and implementation of the new oil and gas law. Efforts were likewise focused on inviting more investor by offering new areas for bid and improvements in the petroleum fiscal system. Indonesia also continues its programs of abolishing the oil subsidy that placed a burden on the state budget for along time. With regards to air quality, Indonesia has phased out leaded gasoline in Jakarta in 2001 and plans to do the same for the entire economy in 2005.

REFORMS

The promulgation of the New Oil and Gas Law, Law No. 22/2001 has abolished the mining right of Pertamina over oil and gas resources. The mining right therefore was returned to the state, and to administer the exploration and exploitation of oil and gas resources Government of Indonesia established the executing body called Badan Pelaksana Kegiatan Hulu Migas (Upstream Oil and Gas Executing Body) called BP-Migas in 2002. BP-Migas signed the cooperation contract on behalf of Government of Indonesia with Oil Company awarded prospective acreage. The prospective acreage is offered to oil companies through a competitive bidding mechanism. To supervise the downstream sector in December 2002 Indonesia has established a Regulating Body to supervise the supply and distribution of fuel oil and the transmission/distribution gas through pipelines. To proceed with the oil sector reform, Indonesia has reduced Pertamina's status to a limited liability company in 2003. Within a period four years, Pertamina's sole right to distribute petroleum products will finally be eliminated.

NEW BID ROUND

In 2002, Indonesia has not been very successful in inviting investors for the prospective areas offered. Out of the 14 working areas tendered, only one investor came to bid. The rigid fiscal system, wherein the government takes too much from the produced oil, is believed to be the main barrier or serious hurdle for prospective and future investors. In order to improve its investment climate, the government of Indonesia has introduced a new fiscal system in 2003. The new fiscal system will allow an increase in production shares for companies from 15 percent to 25 percent for oil and from 30 percent to between 35 percent and 40 percent for gas.

The new fiscal system seemed encouragingly attractive to investors. For the 11 oil and gas working areas offered by Indonesian in July 2003, 36 investors came to bid, and 9 companies then awarded the Production Sharing Contracts, with a total value of US$ 170 million. The government expects that from the new working areas opened for bid, 8 more contracts will be signed, which will bring the total contracts signed in 2003 to 17. This is a big improvement from 2002 where only one contract was signed.

NATURAL GAS INDUSTRY

In 2002 and 2003 Indonesia took serious efforts to, among others, market LNG from Tangguh plant, encourage domestic gas utilisation and restructure its natural gas industry. China, Japan, Korea (South), Mexico, the Philippines, Chinese Taipei, and USA are considered potential buyers for the Tangguh LNG. On the domestic front, Indonesia enhanced gas utilisation for power generation and petrochemical plant (fertiliser). Pertamina, Amerada Hess and Santos with their working area adjacent to BP Kangean field will serve as alternative sources of gas to meet the gas demand, which BP Kangean has recently been unable to supply due declining reserves. Pertamina will supply gas for power generation in East Kalimantan and Central Java. PT Expand Nusantara, on the other hand, will supply gas for power plants in South Sumatra and East Kalimantan. In addition, Indonesia is also proceeding with the construction of the export pipeline following the completion of the third line that supplies gas to Singapore, which went on stream in August 2003.

After the Share Sale of the PT PGN, which established the transportation company, PT Transportasi Gas Indonesia (Transgass indo) in 2002, Indonesia will proceed with the plan for the Initial Public Opering of PT PGN stakes in November 2003. Government will sell the PGN stakes at up to 30 percent.

GAS SUPPLY DEAL

Indonesia achieved some success in marketing gas both for the domestic and export market. In 2003 gas producers in Indonesia have signed 13 agreement to supply gas worth of US$ 14 billion to state- owned electricity company PT PLN, state-owned fertiliser company PT Petrokimia, Gresik and Singapore's utility Island Power.

Indonesia has also signed LNG contracts that proceeded the development of the two train LNG Tangguh with a production capacity of 7 millions ton per year. BP Indonesia has signed a contract with Fujian province to supply 2.5 million ton LNG per year to the province start in 2007. In addition BP also signed an MOU with SK Corporation and Posco of South Korea to supply both companies with an average of 1.1 to 1.5 million tons of LNG per year for 20 years. BP Indonesia has also signed a contract to supply LNG to the Philippines in 2006. Indonesia also considers finding a market for LNG Tangguh in the US and Mexico in collaboration with Sempra and Marathon.

PGN has considered building a gas receiving terminal in West Java and East Java to ensure uninterrupted gas supplies to the island by utilising liquefied natural gas from Tannguh LNG plant in Papua and Donggi in South Sulawesi.

PNG DEVELOPMENT

As early as 2001, Indonesia has continuously increased its gas export through pipelines. In 2002 Indonesia has exported about 226,5 MMSCFD (million standard cubic feet per day) of gas through pipelines the export were delivered through 2 pipelines to Singapore and Malaysia. The first pipeline delivered gas from three production blocks - Block A, Block B and Kakap in Natuna sea to SembGas facilities at Jurong Island at the rate of 126,5 MMSCFD. The 656 kilometer pipeline which has a capacity of 700 million standard cubic feet per day were jointly developed by Conoco, Gulf and Premier. The second pipeline delivered gas from Block B West Natuna to Petronas Carigali Duyong gas facility. The delivery started in August 2002 at the rate of 100 MMSCFD, and is expected to increase at a rate of 250 MMSCFD in 2007.

The third export pipeline was commissioned in August 2003. The 470 kilometer pipe line delivered gas from Grissik Field in South Sumatra to Singapore's Sakra island via Sakerman in Jambi and Batam Island with an initial flow rate of 150 MMSCFD. The capacity will be increase to 350 MMSCFD by 2009. The pipelines will also supply gas at a rate of 150 MMSCFD to Batam island (in what year?).

In addition to its export gas pipelines, Indonesia also plans to build the Indonesian Integrated Transmission Pipelines, which is aimed at meeting the economy's domestic gas demand. The plan includes the development of a pipeline from Sumatra and Kalimantan to Java. A section of the gas grid, the 399 kilometer pipeline linking Grissik to Jakarta via Pagardewa in South Sumatra and Cilegon in West Java with capacity of 550 MMSCFD, already went on stream in 2002.

East Kalimantan - Java pipelines consist of 600 kilometer pipelines from Samarinda (Bontang)-Balikpapan-Banjarmasin and 500 kilometer pipeline from Banjarmasin to Surabaya. The pipelines are expected to deliver 700 MMSCFD of gas by 2005. The inter-Java pipeline linking east-center and west of Java are projected to be completed in 2004 - 2007.

GTL PLANT

Rentech (Matindok) has conducted a feasibility study to build a 16,000 barrel/day gas to liquids plant. Using Fischer-Tropsch technology, the plant is expected to be on stream in 2007. Another company, Shell, is examining the possibility of building GTL plant with a capacity to produce 75,000 barrel per day of diesel and other middle distillates using the same process proposed by Rentech.

POWER SECTOR

Indonesia electricity generation capacity is estimated to be around 23.4 GW of which 84 percent is thermal, 14 percent hydropower, and 2 percent geothermal. Indonesia is still struggling to overcome the shortage of power, both in the main island of Java-Madura Bali and outer islands. Lack of generating capacity and transmission has placed several areas in high risk of having a power shortage. To address this problem GOI has renegotiated the 27 postponed IPPs. In the first quarter of 2003, PLN and the government has thus far resolved price disputes with 20 of the 27 independent power producers that were licensed in the early 1990s. From 26 IPP projects negotiated, 14 projects have proceeded for construction, 7 projects were closed and 5 projects were acquisitioned by State Power Company. However, most of the projects will come on stream only within the next three to four years. PLN itself is building a new power station with a capacity of 850 MW at Muara Tawar in West Java but this one too is only expected to come on line next year.

The power-capacity level will thus remain dangerously low, making industrial users in Java and Bali highly vulnerable to supply disruptions. It is therefore more imperative than ever for PLN to improve its peak load management, maintenance system and cooperation with captive power suppliers to avert major power blackouts during this critical period until enough additional capacity comes on stream to increase the power reserve margin much higher than the minimum 30 percent, a standard recommended by World Bank.

With the implementation of the new electricity law, passed by Parliament in 2002, PLN will gradually loose monopoly in power generation, transmission and distribution, and the private investors will be allowed to enter the electricity sector. The electricity market is planned to be liberalised in 2007. To supervise the electricity market, Government of Indonesia has established a Power Market Supervisory Agency called BAPETAL (Badan Pengatur Tariff Listrik). The power industry watchdog will determine which province in the economy is ready for market competition, and which will remain under government control. The supervisory body will be in charge of ensuring fair market competition for mid sized and large consumer and determining power prices for small users. Java, Madura, Bali (Jamali) and Batam islands will become the first areas were open market competition will be applied.

GEOTHERMAL

Indonesia is estimated to own 40 percent of world's geothermal resources or equivalent to 20,000 MW. However, only 4.3 percent or 860 MW have been utilised. To enhance the utilisation of its geothermal resources, Indonesia has promulgated the Geothermal Law in 2003. The law provides legal certainty and security to investors, establish the regulating body and transparent business procedures.

COAL

The decision made by BP Plc and Rio Tinto to sell their entire stake in the economy's second largest coal producer, PT Kaltim Prima Coal, to a local company PT Bumi Resources has raised some concerns. Some experts argued that the divestment, where BP Plc and Rio Tinto considered sold the stake in low price indicated that the companies frustration in dealing with the uncertainty in the economy mining policy, such as high taxes, lack of security guarantees and legal inconsistency as a result of regional autonomy. Following the divestment, the KPC workers called for more than two-week strike and insisted financial compensation that caused some delay in contract delivery, whereby company lost up to US$ 500,000 per day.

Despite the hurdles faced by the divestment KPC, PT Tambang Batu Bara Bukit Asam (PTBA), the state owned company, discovered around 200 million tons of new coal reserves at Ombilin in West Sumatra. To develop the resource Indonesia has established it ties with the Japan Energy Coal Center (JCOAL).

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JAPAN

INTRODUCTION

Japan is a small island nation in Eastern Asia. It consists of several thousand islands, the largest of which are Honshu, Hokkaido, Kyushu and Shikoku. It spans across a land area of approximately 377,800 square kilometres, more than half of which is mountainous and thickly forested.

Japan is the world's second largest economy after the USA. Japan's real gross domestic product (GDP) in 2001 was about US$ 3,027 billion (1995 US$ at PPP). With a population of 127 million people, per capita income was high at US$ 23,828.

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 0.3 percent in 2001 after 2.8 percent in 2000. The unemployment rate reached 5 percent in 2001.

Japan possesses a moderate amount of indigenous energy resources and imports almost all of its crude oil, coal and natural gas requirements to sustain economic activity. In 2001, proven energy reserves included around 9 MCM of oil, 40 BCM of natural gas and 773 Mt of coal.

Table 15 Key data and economic profile (2001)

Key data		Energy reserves*	
Area (sq. km)	377,800	Oil (MCM) - Proven	9.3
Population (million)	127.03	Gas (BCM)	40
GDP Billion US$ (1995 US$ at PPP)	3,026.99	Coal (Mt) - Recoverable**	773
GDP per capita (1995 US$ at PPP)	23,828		

Source: Energy Data and Modelling Center, IEEJ. * Oil & Gas Journal. ** World Energy Council.

ENERGY DEMAND AND SUPPLY

PRIMARY ENERGY SUPPLY

Japan's total primary energy supply (TPES) was 508 Mtoe in 2001. By fuel, oil represented the largest share at 49 percent, coal was second at 19 percent, followed by natural gas at 13 percent, nuclear at 13 percent, hydro at 4 percent and NRE, including geothermal, wind and others at 1 percent. In 2001, 82 percent of the total primary energy was imported. Imports account for almost 100 percent of oil consumption, 99 percent of coal demand and 97 percent of gas use. Total primary energy supply fell by 0.3 percent in 2001.

Japan is the world's second largest oil consumer after the United States, and almost all of the oil is imported. The bulk of these imports (82 percent in 2001) come from OPEC economies such as the United Arab Emirates (UAE), Saudi Arabia, Iran, Qatar and Kuwait. In 2001, the primary oil supply was 248 Mtoe, a decline of 3 percent from the previous year.

Japan is endowed with only limited coal reserves at 773 million tonnes. The small amount of coal production had been heavily subsidised until 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, Indonesia, Russia, the United States, South Africa and Canada. Coking coal is imported from Australia, Indonesia, Canada, China, Russia, the

United States and South Africa. In 2001 primary coal supply was 95 Mtoe or 4.2 percent higher than the previous year.

Natural gas resources are also scarce in Japan. Domestic reserves stand at 40 BCM, located in Niigata, Chiba and Fukushima prefectures. Domestic demand is met almost entirely by imports of LNG[4], which come mostly from Indonesia (30 percent of imports in 2001), Malaysia (21 percent) and Australia. Natural gas is mainly used for electricity generation (71 percent of total usage in 2001), followed by reticulated city gas (28 percent) and industrial fuels (1 percent). In 2001, primary natural gas supply was 67 Mtoe, an increase of 3.6 percent over the previous year. Both power and city gas sectors are responsible for the growth of the natural gas demand.

Japan has 262 GW of installed generating capacity and has generated about 1,050 TWh in 2001. The fuel, generation is broken-down as: thermal (coal, natural gas and oil) at 61 percent, nuclear at 29 percent, hydro at 8 percent and geothermal, solar and wind taking up the comprising remainder. Due to increased interest and investments 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 49 percent, its lowest level since 1963.

Table 16 Energy supply & consumption for 2001

Primary Energy Supply (ktoe)		Final Energy Consumption (ktoe)		Power Generation (GWh)	
Indigenous Production	101,828	Industry Sector	153,560	Total	1,049,885
Net Imports & Other	405,721	Transport Sector	86,601	Thermal	637,593
Total PES	507,549	Other Sectors	113,672	Hydro	82,074
Coal	94,747	Total FEC	353,833	Nuclear	306,777
Oil	248,064	Coal	35,170	Others	23,440
Gas	67,269	Oil	209,479		
Others	97,469	Gas	22,806		
		Electricity & Others	86,377		

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 on for power generation. Energy production from nuclear sources has increased dramatically from 1973 to 1998, averaging 15.2 percent per year. In 2001, the primary nuclear supply has accounted for 307 TWh of output, representing 29 percent of the total electricity supply. The utilisation factor for all nuclear units was 80.5 percent in 2001. With 51 units in operation in 2001, Japan ranks third worldwide in installed nuclear capacity, next to the United States and France. However, during the past few years, public opposition to nuclear development has increased due to a series of accidents.

FINAL ENERGY CONSUMPTION

In 2001, Japan's total final energy consumption was 354 Mtoe, or 1.7 percent lower than the previous year. The industrial sector consumed 44 percent of the total, followed by the other sectors mainly residential/commercial at 32 percent and the transportation sector at 24 percent. By fuel source, petroleum products accounted for 60 percent of the total final energy consumption, followed by electricity and others at 24 percent, coal at 10 percent and city gas at 6 percent.

Energy consumption in the industrial sector decreased by 4.5 percent in 2001 reflecting a reduced production in almost all industries with recession, though it had 4.6 percent growth in 2000.

[4] In 2001, LNG imports to Japan comprised 52 percent of total world LNG trade.

In 2001, the residential/commercial sector, electricity has accounted for 45 percent of total energy consumed, followed by petroleum products at 34 percent, city gas at 19 percent, solar heat at 1 percent and coal at 1 percent. The residential sector's energy consumption decreased due to mild weather but the commercial sector's energy consumption increased due to business hours extension with a change of consumers' life-style. The energy consumption of the residential/commercial sector grew by 1.5 percent.

In the transportation sector, the passenger sector accounted for 65 percent of the total energy consumption while the remaining 35 percent went to the freight sector. Although the passenger sector's energy consumption increased steadily with the growing number of passenger-cars, freight sector's energy consumption, however decreased, reflecting slow economic activities. In 2001, energy consumption in the transportation sector fell by 0.4 percent.

POLICY OVERVIEW

The Ministry of Economy, Trade and Industry (METI) is responsible for formulating Japan's energy policy. Within METI, the Agency for Natural Resources and Energy (ANRE) is responsible for the rational development of mineral resources, securing stable supply of energy, promoting efficient energy use, and regulating electricity and other energy industries. The Nuclear and Industrial Safety Agency (NISA) is responsible for the safety of energy facilities and industrial activities while the Ministry of Foreign Affairs formulates international policies.

The fundamental goal of the Japanese energy policy is to achieve a stable energy supply in response to the demands for environmental conservation and efficiency improvement.

Japan is currently faced with several key energy issues. One is securing stable energy supplies to satisfy the growing energy demand in the residential/commercial and transportation sectors. Second is on how to meet the Kyoto Protocol commitment, negotiated at COP3, to reduce greenhouse gas (GHG) emissions to 6 percent below the 1990 levels by 2008 to 2012. Third is how Japanese industries, including the energy sector, can best restructure to improve their economic efficiency and thereby increase their domestic and international competitiveness.

OIL

Japan has aimed to decrease its dependency on oil due to past experiences of the oil crises. However oil is expected to remain as a major energy source since it still accounts for around 50 percent of Japan's total primary energy supply. Securing therefore the stable supply of oil will continue to be one of Japan's major energy future policy issues. Japan imports almost all of its crude oil from the Middle East (dependency on the Middle East in 2001 was 88 percent). Japan's supply structure for oil is vulnerable. This is why Japan is effectively and efficiently pursuing measures for stockpiling oil, conducting independent development of resources and promoting cooperation with oil producing economies for emergency situations. The Japan National Oil Corporation (JNOC) has carried out the national stockpile business. In 2001, their functions of the national stockpile business was decided to be shifted to the Metal Mining Agency of Japan in the Specially Designated Public Corporation Reduction Rationalisation Plan.

The government has pursued oil and natural gas exploration and development both domestically and abroad. Industry players have actively joined many projects abroad through the financial and technical assistance of JNOC. However, in 2001, these functions were decided to be integrated into the Metal Mining Agency of Japan.

In order to secure long-term stable supply of oil, it is highly important to strengthen relations with oil producing economies. Recently there can be found a trend of reviewing government policies of the oil producing economies concerning national ownerships of resources. Many economies have again begun to release mining concessions to private enterprises. It is essential to actively promote joint research projects, human resource exchange programmes and direct investment, not only in the oil and natural gas fields, but also in other areas.

The oil industries are having made every effort for rationalisation with huge cost reduction, like downsizing and tie-up with distributors. The reorganisation of the structure and consolidation of the groups are still ongoing. Making a strong oil industry through the promotion of rationalisation and efficiency is also important for the energy security in Japan.

NATURAL GAS

In 1969, the first LNG cargo for Japan reached Tokyo Bay from Alaska, USA. Now Japan imports LNG from Brunei Darussalam, United Arab Emirates, Indonesia, Malaysia, Australia, Qatar and Oman besides USA. In 2001, natural gas accounts for 13 percent of total primary energy supply , although before the introduction of LNG, natural gas accounted for around 1 percent of the total primary energy supply. Natural gas is supplied almost entirely by imports from the Asian Pacific region from Indonesia, Malaysia, Brunei Darussalam and Australia. LNG is mainly consumed for thermal generation of electricity and is also used for city gas.

While there are still many gas companies supplying low calorific value gas (such as reformed gas of naphtha and butane), they are promoting conversion to natural gas to meet the 2010 goals as prescribed in the Integrated Gas Family Plan.

The Gas Utility Industry Law was amended again in 1999 and the scope of deregulation for large volume supply was extended by lowering the annual contract volume to 1 million cubic meters and over. Regulations for third-party access for large volume supply were also established. To date, system reforms are being considered to extend the deregulation to consumers, which have an annual contract of 500,000 cubic meters and over starting 2004.

Because of its large reserves and geographical proximity to Japan, the Sakhalin project is regarded as having a high potential to become a big new supply source of gas for Japan. The government of Japan may however need to examine the feasibility or necessity of using its public funds for the project should private resources becomes unavailable.

COAL

In 2001, coal accounted for 19 percent of the total primary energy supply. According to the Long-term Energy Supply-Demand Outlook (July 2001), coal will account for approximately 19 percent of the total primary energy supply in 2020 and will continue to play an important role in Japan's energy sector. Coal mines in Japan have become increasingly deeper and remoter and the mining costs are approximately three times that of imported coal. The government has since then subsidised the coal mining industry and has achieved structural adjustments by reducing coal production gradually. The domestic production of commercial coal substantially ended at the end of fiscal year (FY) 2001.

Japan is the biggest importer of coal, with imports reaching over 20 percent of the total imported coal in the world. From its standpoint, it is essential therefore to promote the development of overseas coal for energy security in Asia, to address its growing coal demand. To secure a stable supply of overseas coal, Japan is implementing a five-year plan to transfer coal-mining technologies overseas in economies with still abundant coal resources. Some of the concrete measures to support overseas coal development, include subsidies for investigations prior to mine exploration and development and loans for mine exploration, technology cooperation with coal producing economies and for environmental concerns, development of technology to improve heat efficiency such as technologies of pressurised fluidised-bed combustion, coal gasification combined power generation and coal gas production for fuel cells, support to introduction of high efficiency coal boilers and development and diffusion of Clean Coal Technologies (CCT).

ELECTRICITY

The Electricity Utilities Industry Law, the main legislation covering the electricity industry, was amended in 1995 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.

Subsequent amendment in 1999, allowed 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 enter into contracts with power suppliers, including IPPs.

NUCLEAR ENERGY

Nuclear energy is perceived to address two key energy issues: supply stability and the environment (no CO_2 emissions). It has now become a major source for electric power generation and will most likely play a big role in the future. To achieve its goal of supply stability and environmental sustainability, Japan is expected to install at least 10 to 13 nuclear power stations more by 2010 (according to the Long-term Energy Supply-Demand Outlook (July 2001)). However, it is deemed necessary that significant and sufficient dissemination of information about the safety and necessity of nuclear power is necessary in order to get the national and regional support. The government has undertaken several promotion measures for the siting of the future nuclear power stations.

To ensure efficient use of nuclear resources, it is essential to work out countermeasures to establish the nuclear fuel cycle. In May 2000, the “Specified Radioactive Waste Disposal Act” was approved to ensure the planned, and most importantly reliable execution of high-level radioactive waste disposal. In October 2000, authorisation was granted by METI to establish the Nuclear Waste Management Organisation of Japan (NUMO). NUMO is responsible for identification of the disposal site, construction, operation and maintenance of the repository, closure of the facility and post-closure institutional control. The Low-level Radioactive Waste Disposal Center of the Japan Nuclear Fuel Limited (JNFL) has been in operation at Rokkasho-mura in Aomori Prefecture since 1992.

ENERGY CONSERVATION

Japan has achieved the highest level of energy efficiency compared with any economy anywhere in the world since the oil crises. However, the Japanese structure of energy supply remains vulnerable and the level of dependency on Middle East crude oil is still higher than at the time of the oil crises. Therefore, to meet the increasing demand mainly in residential/commercial and transportation sectors, further steady promotion of energy efficiency measures is needed.

Japan formulated its energy efficiency measures as early as 1998, and has aimed at achieving its target commitment set forth at the Kyoto Conference on Climate Change (COP 3). In 2000, the Advisory Committee for Natural Resources and Energy started the total review of energy policy and the Energy Efficiency and Conservation subcommittee has re-evaluated the energy efficiency measures and has added measures to address the increasing energy demand in the residential/commercial and transportation sectors.

The current energy efficiency measures include, are measures for factories based on Law Concerning the Rational Use of Energy, a follow-up of the Keidanren environmental voluntary action plan in the industry sector, strengthening efficiency improvement of equipment and improvement of energy efficiency performance of houses in the residential/commercial sector, strengthening fuel efficiency improvements in cars and acceleration of the popularisation of clean-energy motor vehicles in the transportation sector.

NOTABLE ENERGY DEVELOPMENTS

ELECTRICITY AND GAS MARKET REFORM

In June 2003, the Diet passed the "Amendments of Electricity Utility Law and Gas Utility Law". The aim is to expand the degrees by which the liberalised market is implemented as outlined below. The framework has been settled but it needs some time to discuss in details.

Timetable of the market liberalisation by volume are:

- Electricity: Current/26 percent, April 2004~/40 percent, April 2005~/63 percent; and
- Gas: Current/40 percent, April 2004~/44 percent, April 2005~/50 percent.

TEPCO'S NUCLEAR POWER PLANTS

Tokyo Electric Power Co. (TEPCO) has successively shut down all of its nuclear power plants for inspection, seven in Niigata Prefecture and ten in Fukushima Prefecture, after the infringements of safety regulations were revealed last year (2002). In May this year (2003), TEPCO restarted one of their plants in Niigata Prefecture.

Taking into account the volume secured as of June, TEPCO anticipated power shortage during their peak demand in summer. While it seemed necessary to restart the other plants to meet the demand, TEPCO asked large-scale consumers to restrain their consumption. The government was concentrating on monitoring the market situation, promoting public relations activities for energy efficiency, and conducting briefings to gain approval from the local communities.

As a result of these efforts, TEPCO expects to manage and overcome the difficulties brought about by a sharp decline of demand from an abnormally cool summer, procurement from other utilities and restarting of some other plants. As of end September, five plants are in operation.

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KOREA

INTRODUCTION

Korea is located in East Asia between China and Japan. It has an area of about 99,538 square kilometres and a population of around 47 million (2001). Approximately 21 percent of the population lives in Seoul, Korea's largest city, its capital.

In the last decades, Korea has been one of Asia's fastest growing and most dynamic economies. Its GDP has moved at an unprecedented growth of 7.2 percent per year (simply calculation error) over the period 1980 to 2001, reaching US$671.7 billion (1995 US$ at PPP) in 2001. Its per capita income in 2001 reached US$14,187, more than three times higher than its 1980 level. Despite the global recession, the economy has achieved a still solid real GDP growth of 6.3 percent in 2002. Its major industries include semi-conductor, electronics, shipbuilding, automobile, steel and chemicals.

In 2001, Korea was the fourth-largest importer of crude oil and the second-largest importer of both coal and liquefied natural gas in the world. It has very limited indigenous energy resources, and is completely without oil reserves. At the end of 2001, there were only 646 Mt of recoverable coal reserves and 5.7 BCM of a recently discovered small natural gas. Imports meet more than 80 percent of its energy requirements.

Table 17 Key data and economic profile (2001)

Key data		**Energy reserves***	
Area (sq. km)	99,538	Oil (MCM)	-
Population (million)	47.34	Gas (BCM) - Recoverable	5.66
GDP Billion US$ (1995 US$ at PPP)	671.67	Coal (Mt) - Recoverable**	340
GDP per capita (1995 US$ at PPP)	14,187		

Source: Energy Data and Modelling Center, IEEJ. * Heat content is 10,200 kcal/m^3.

** MOCIE & KEEI, *Yearbook of Energy Statistics 2003*, 2003, p.166.

ENERGY DEMAND AND SUPPLY

PRIMARY ENERGY SUPPLY

Korea's total primary energy supply in 2001 was 190 Mtoe. By fuel type, oil represented the largest share at 51 percent, coal at 22 percent, nuclear at 17 percent and gas at 10 percent. The remaining 2 percent of primary energy came from hydro and other fuels. In 2001, Korea imported around 82 percent of its total energy needs, including all of its oil and gas requirements and 95 percent of its coal supply. Total primary energy rose by a modest 1.4 percent in 2001 against a high growth rate of 7.4 percent in 2000 , due mainly to the relatively sluggish economy.

Oil is Korea's most important fuel accounting for (or amounting to) half or 51 percent of the primary energy mixes in 2001. Primary oil supply, however, declined from 99 Mtoe in 2000 to 97 Mtoe in 2001, a decline rate of 2.2 percent. Korea is the world's sixth-largest consumer of oil, all of which is imported. In 2001, the economy imported about 77 percent of its oil from the Middle East.

Coal use in 2001 totalled 42 Mtoe, 4.9 percent higher than the previous year, reflecting the rapid growth of steam coal demand for power generation. The power sector's share of coal consumption reached 63 percent in 2000, from 23 percent in 1990. Korea has modest reserves of low-quality, high-ash anthracite coal which is not enough to support its demand. Almost all of

Korea's coal demand therefore is met by imports. Korea is the world's second-largest importer of both steam and coking coal after Japan. Coal imports come from China, Australia, Canada, South Africa, Indonesia, Russia and the US.

Korea introduced natural gas in the form of LNG in 1986. Since then, gas use has grown rapidly, reaching up to 19 Mtoe in 2001, increasing to 10 percent its share in the primary energy supply mix. Korea buys the bulk of its LNG from Indonesia, Qatar, Malaysia, Oman and Brunei Darussalam. Recently, a small quantity of natural gas, with 5.66 BCM of recoverable reserves, was discovered in the Donghae-1 offshore field, southeast of the economy. Donghae-1 is expected to begin commercial operation in the first half of 2004, a little behind schedule due to such technical issues as difficulties in employing HDD method in laying undersea pipes and safety reinforcement for facilities.

Korea's electricity generation in 2001 was 285 TWh, 7.1 percent more than in 2000. Nuclear produced 39.3 percent of the total electricity generation, followed by coal at 38.6 percent, gas at 10.7 percent, oil at 9.9 percent and hydro at 1.5 percent. The installed capacity in 2001 reached 50.9 GW. There are currently 18 nuclear power plants with total installed capacity of about 15.7 GW.

Table 18 Energy supply & consumption for 2001

Primary Energy Supply (ktoe)		Final Energy Consumption (ktoe)		Power Generation (GWh)	
Indigenous Production	33,667	Industry Sector	74,474	Total	285,225
Net Imports & Other	156,556	Transport Sector	30,323	Thermal	168,941
Total PES	190,224	Other Sectors	41,203	Hydro	4,151
Coal	42,273	Total FEC	146,000	Nuclear	112,133
Oil	97,175	Coal	19,506	Others	-
Gas	18,740	Oil	88,762		
Others	32,035	Gas	11,961		
		Electricity & Others	25,771		

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

FINAL ENERGY CONSUMPTION

Final energy consumption has grown rapidly in the 1990s, averaging more than 7 percent annually to a total of 146 Mtoe in 2001. By sector, industry consumed the largest at 51 percent, followed by residential and commercial buildings at 28 percent and transport at 21 percent. In general terms, demand growth in the industry has weakened since the early 1990s, while the pace of demand growth in the transport and commercial sector has quickened.

By fuel source, petroleum products were the most important energy source, accounting for 61 percent of demand. Electricity was responsible for 18 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 2001.

POLICY OVERVIEW

The Korean government has traditionally intervened heavily in the energy sector. Supporting high levels of economic growth despite inadequate indigenous energy resources has been the key driver of Korea's energy policy platform. The Ministry of Commerce, Industry and Energy (MOCIE) is responsible for developing and implementing energy policies and programmes, maintaining energy security, administrating the energy industry, supporting research and development of new energy technologies and formulating international cooperation on energy-related matters.

Korea has announced "The 2nd National Basic Plan for Energy Policy" in December 2002. The Plan provides for Korea's plan of action towards transforming its energy policy paradigm, by incorporating the new and changing environments to its energy policies. The objective of the past energy policy was the stable energy supply, but with a recently added dimension of environment protection, a new objective has been set for sustainable development. In terms of operation of energy market, with due regard to the recent world trend of efficiency and privatisation, Korea is undergoing a shift from government-controlled system into market-oriented system. In addition, since world energy market has rapidly been integrated and with the advent of regional energy cooperation, especially in northeast Asia, emerging as an important issue, Korea is now pursuing an active international role with an open energy system. Korea is set to put more resources in new energy technology development.

In summary, the following four dimensions comprise Korea's energy policy:Objective - sustainable development;

- Energy market - from government-controlled system to market-oriented system;
- International relation - open to outside markets and regional cooperation; and
- Activity - support to technological innovations.

OIL

Due to Korea's complete dependence on oil imports, the government has been trying to secure and diversify supplies in the short and long term. To smoothen 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 44.5 days of net imports in April 2002 (65.6 million barrels) to 60 days by 2006.

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 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

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. Since then, gas use has grown rapidly, replacing coal and oil in the residential sector, to reach 10 percent share of primary energy supply in 2001.

Ensuring a stable supply base through timely establishment of energy supply facilities is one of the important policy measures to achieve energy security goals. The entire gas transmission network, including all LNG receiving terminals and natural gas pipelines, is owned and operated by the Korea Gas Corporation (KOGAS). LNG storage capacity increased to 2.6 MCM in 2002 from 2.3 MCM in 2001 when the third LNG terminal at Tongyeong on the southeast coast began operation 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 early 2004.

ELECTRICITY

Demand for electricity has gone up quite substantially for the last few decades, marking 9.4 percent average annual growth through the 1990s. The installed capacity in 2002 reached 53.8 GW from 21 GW in 1990, more than two-fold increase. According to “the Basic Plan of Long Term Electricity Supply and Demand”, which was finalised by MOCIE in August 2002, it is projected that electricity demand would grow by 3.3 percent per annum from 2001 to 2015 and 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 power plants since the 1970s, and nuclear power now accounts for around 40 percent of electricity production. The capacity share of nuclear is envisaged to increase to 34.6 percent in 2015 from 29.2 percent in 2002, surpassing the traditionally largest share of coal-fired capacity. Ten additional nuclear power plants by 2015 will be built, including two currently under construction.

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 to 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. The power generation part of KEPCO was split into six companies. Five generating companies except for hydro and nuclear stations will be privatised step by step. Though a year behind schedule, separation of KEPCO’s distribution arm will be launched in April 2004. 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. 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.

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 savings of about 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

THE 2ND NATIONAL BASIC PLAN FOR ENERGY POLICY

The Korean government announced the "The 2nd National Basic Plan for Energy Policy" in December 2002. The plan is established every five years in accordance with the Rational Energy Utilisation Act, and each time the plan is based on a 10-year timeframe. This plan has four main policy goals for establishing an energy sector that is: sustainable; market-oriented; open to outside markets; and technologically innovative. It also includes basic plans for the seven major energy sources of oil, gas, electricity, coal, new and renewable energy (NRE), community energy, and general minerals.

In the plan, Korea has established a goal for NRE to account for 5 percent of total primary energy supply by the end of 2011. In particular, the government has chosen three sources of NRE in 2001, namely wind power, fuel cell, and photovoltaic, as the major sectors for technology development. A notable turning point in expanding the supply of NRE is the construction of a large commercial wind-power generation complex, which started in November 2002. Korea plans to construct 49 more wind-power plants by November 2004.

NUCLEAR WASTE STORAGE FACILITY

Korea needs to build the low-and-intermediate-level radioactive waste (LILW) repository by 2008 and the spent fuel storage facility by 2016. Building a permanent site for nuclear waste is a top priority, as the government has unsuccessfully tried to secure a suitable location since 1986. As of now, Korea has 18 nuclear plants in operation with large amounts of nuclear waste currently being stored at temporary sites. About 6,000 tons of spent fuel and 60,000 drums of 200 liters of LILW were kept on-site as of the end of 2002.

In July 2003, the government (MOCIE) called for local communities to volunteer to host a disposal facility. Buan County, North Jeolla Province put up a bid to host the facility in Wido, an island located in a southwestern area. The government announced Wido as the site for the nation's first nuclear waste disposal facility despite protests by residents. The subsequent process for constructing the facility - including site examination, land purchases, issuance of construction permits and designing detailed structural plans - will be completed by September 2006. The actual construction will begin in October 2006, with the low-and-medium-level nuclear waste storage facilities due to be completed by 2008.

SUPPLY OF 30,000 SOLAR-HEATING HOUSES BY 2010

The Korean government is supposed to supply a “3 kW Solar Power Generation System for House” to 30,000 houses and is planning and seeking “Development and Provision Strategy of Solar (Solar Land 2010 Program)”. Intensively supporting a “3 kW Solar Power Generation System for House” and “Next-Generation Thin Film Solar Battery,” the government is gradually seeking to increase cell efficiency, to reduce unit cost of system and to save power generation cost.

The government reinforces the basis for commercialising the developed technology and products by introducing a certification system for equipment, designating a center for evaluation of quality, and building practical research complex and green village. On the other hand, the government is planned to reinforce the economics and create the market by building Solar City, supporting the difference between generating cost and market price of electricity.

DELAY OF STRUCTURAL REFORM PROCESS IN POWER INDUSTRY

Korea is undergoing regulatory reforms in electricity sector. The restructuring process was supposed to commence with privatisation of KEPCO’s generation assets. The restructuring plan envisages a gradual transition to wholesale competition, with the introduction of retail competition after 2009. As the initial period, in April 2001, the power generation part of KEPCO was split into six companies. One of the six companies was planned to be privatised by 2002. Subsequently, KEPCO’s distribution assets were planned to be divided into a number of companies by 2003.

The above schedule for the initial stage of reform was however delayed and has been revised such that: one of power generation companies will be floated in the stock market within 2004; and the division of distribution assets of KEPCO and following two-way bidding pool system is pending depending on the result of the discussion between labour and government in the Korea Tripartite Commission.

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MALAYSIA

INTRODUCTION

Malaysia is located in southeast Asia. Its 330,242 square kilometres of territory consist of Peninsular Malaysia and East Malaysia which has the states of Sabah and Sarawak. The total population of Malaysia was 24.3 million in 2001 with an average annual growth of 2.3 percent.

The Asian financial crisis in 1997 severely affected Malaysia's economy. GDP grew at an average of 9.2 percent per year from 1990 to 1997 but contracted to 7.4 percent in 1998. Malaysia's 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 2001, Malaysia's GDP recorded a growth of 0.4 percent, reaching US$185 billion or US$7,802 per capita (both in 1995 US$ at PPP). The lower growth in GDP was attributed to the global economic slow down in 2000 and 2001and the contraction of exports (11 percent), but a substantial fiscal stimulus package mitigated the worst of the negative effects and the economy rebounded in 2002. 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 2001, reserves included 3.4 billion barrels of oil, 82.5 tscf of gas, 1,483 million tonnes (Mt) of coal, and 29,000 MW of hydropower capacity. Malaysia is a net energy exporter. Seven percent of its export earnings in 2001 came from mineral fuels and petroleum products.

Table 19 Key data and economic profile (2001)

Key data		Energy reserves*	
Area (sq. km)	330,242	Oil (Bbbl)	3.39
Population (million)	23.8	Gas (Tscf)	82.5
GDP Billion US$ (1995 US$ at PPP)	185.71	Coal (Mt) - Recoverable	1,483
GDP per capita (1995 US$ at PPP)	7,802		

Source: Energy Data and Modelling Centre, IEEJ.

* Proved reserves at the end of 2001 from the National Energy Balance Malaysia, 2001.

ENERGY DEMAND AND SUPPLY

PRIMARY ENERGY SUPPLY

Total primary supply in 2001 was 61,595 ktoe. Gas accounted for 58 percent of total primary supply, while oil, coal and others accounted for 36 percent, 5 percent and 1 percent respectively. Most of the coal used in Malaysia was imported. Net energy exports of oil and natural gas made up 29 percent of total indigenous energy production.

Malaysia produced[5] 35 million tonnes of crude oil in 2001. Almost 87 percent of oil produced 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. Petronas, the state oil and Gas Company, is investing in exploration and production projects outside of Malaysia. At the end of March 2003, Petronas had set up operations in 34 countries with 39 exploration and production ventures in 21 countries. During the same

[5] BP 2003 Statistical Review of World Energy

period, Petronas had also signed 17 new production-sharing-contracts, bringing the current total to 57 ventures in 25 countries. Petronas' international operations contributed 75 percent of the company's group revenue for financial year 2002/2003.

Gas production in Malaysia reached about 45.2 Mtoe in 2002[6], an increase of 183 percent from 1990. Forty one percent of this gas was exported, usually in the form of liquefied natural gas (LNG), to Japan, Korea and Chinese Taipei. A small percentage of the gas is exported to Singapore by pipeline. Gas is used domestically for electricity generation and as a feedstock in the petrochemicals industry.

In 2001, total electricity generation was 83,597 GWh. Thermal generation, mostly from natural gas, accounted for 77 percent of production and hydropower for the remaining 23 percent.

Table 20 Energy supply & consumption for 2001

Primary Energy Supply (ktoe)		Final Energy Consumption (ktoe)		Power Generation (GWh)	
Indigenous Production	87,486	Industry Sector	11,853	Total	83,597
Net Imports & Other	-25,891	Transport Sector	13,138	Thermal	63,980
Total PES	61,595	Other Sectors	6,525	Hydro	19,616
Coal	2,911	Total FEC	31,516	Nuclear	-
Oil	22,207	Coal	977	Others	-
Gas	35,845	Oil	20,324		
Others	632	Gas	4,621		
		Electricity & Others	5,594		

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

FINAL ENERGY CONSUMPTION

In 2001, total final energy consumption in Malaysia was about 32 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 64 percent of consumption followed by electricity (18 percent), gas (15 percent) and coal and coke (3 percent).

POLICY OVERVIEW

The Prime Minister's Department, the Ministry of Energy, Communications and Multimedia and the Energy Commission 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

[6] BP 2003 Statistical Review of World Energy

(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 about 1.8 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 18 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 35 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, with renewable energy as the fifth fuel. This is attributed to the recognition of the technical potential of renewable energy resources in Malaysia. It also is a reflection of Malaysia's commitment to promote renewables and preserve the environment.

THE UTILISATION OBJECTIVE

The Government recognises the importance and benefits of energy efficiency for the country's development. Government policies on EE are contained in the official government Budget and Development Plans such as the Five Year Eight Malaysia Plan (2001-2005) and the Ten Year Third Outline Perspective Plan (OPP3) (2001-2010). Fiscal incentives for companies investing in EE equipment and services were provided for in the 2001 Budget and extended in the 2003 budget up to the year 2005. 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 (MIEEIP) launched in July 1999 is a collaborative effort between the government of Malaysia and the United Nation Development Programme (UNDP)/Global Environmental Facility (GEF).

The aim of this four-year project is 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.

Energy efficiency efforts in buildings started as early as 1980s in Malaysia. The new office premises of the Ministry of Energy, Communications and Multimedia office in Putrajaya, which will be completed by early 2004, has being designed as an EE or "Low Energy Office (LEO) Building". It would be the first, large Government office building to be specifically designed with EE, and cost-effective features and would become a showcase building to demonstrate that EE buildings can be built without excessive, construction cost penalty. It is hoped that other public and private sector buildings replicate such EE measures in their buildings. The design of the LEO building predicts an economically viable, low energy use building, using proven technology, with a cost premium that permits capital outlay recovery within 10 years, and without affecting the project construction schedule target.

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

MALAYSIAN INDUSTRIAL ENERGY EFFICIENCY IMPROVEMENT PROJECT (MIEEIP)

Energy has been a major input to Malaysia's rapid industrialisation and economic growth, especially during the 1980s. However, Malaysia remained one of the high energy-intensity economies within the APEC region until the late 90s. The Malaysian Industrial Energy Efficiency Improvement Project (MIEEIP) was developed and launched in 1999 and its main goal was to remove barriers to energy conservation (EC) and energy efficiency (EE) in the Malaysian industrial sectors, particularly, in the cement, ceramic, glass, pulp and paper, iron and steel, wood, food and rubber sectors.

There was a need at that time, to implement and sustain long-term EE efforts that both improve Malaysia's economic and industrial efficiency and have a well positive impact on the global as well as the local environment. Thus, the support from the UNDP - Global Environment Facility (GEF) was needed to train and assist industrial plant managers to prepare EE&EC projects and when necessary to secure the external private financing required to implement such projects.

This project is a national priority because as it would help in increasing EE initiatives and facilitate in reducing Greenhouse Gas (GHG) emissions. It is also a national priority within the context of the national environment strategy and national energy policy. The project itself is expected to lead to investments in energy efficiency practices/technologies in Malaysia's industrial sector. The MIEEIP has eight components that had been identified as critical in order to realise the objectives of the project.

ENERGY-USE BENCHMARKING COMPONENT

As part of the MIEEIP project, an Energy-use Benchmarking Community had been established at the National Productivity Corporation as a daily productivity tool. Energy-use benchmarking had also been established for eight industrial sectors through energy audits and voluntary participation by the respective industries. Information on benchmarking has been disseminated to three sectors: iron & steel, rubber and cement. The same information will be shared with the pulp & paper and glass sectors.

ENERGY AUDIT COMPONENT

A total of 48 energy audits had been carried out for the eight-targeted sectors, namely cement, ceramic, food, glass, iron&steel, pulp&paper, rubber and wood. Initial findings show that potential for savings in energy consumption is at an average of 23 percent throughout the industries that do not have proper energy management programmes. The MIEEIP has also formed sectoral audit teams, comprising of industry members, the industrial associations and PTM (Pusat Tenaga Malaysia or Malaysia's Energy Centre) to ensure the sustainability of energy audits. The sectoral teams will also regularly conduct training and consultancy.

The component is also in the final stages of preparing the energy audit guidelines for the use of energy professionals and the industries. This will be the first for the industrial sector, giving energy auditors tips and recommendations on carrying out energy audits.

In addition, the team has prepared the report on the component's stretched goals – to extend the audit programme to six factories from three other sectors - plastic, textile and chemicals. This is to further develop the capacity building goals as well as to involve the small and medium industries in the audit programme. The proposal has been endorsed by the National Steering Committee (NSC), which decides on the overall direction of the project.

ENERGY RATING COMPONENT

Motor has been identified as the first priority under this programme as it comprises 70 percent of energy equipment used in the industrial sector. After conducting an impact study, it was decided to site the motor testing facility at Standards and Industrial Research Institute of Malaysia Berhad (SIRIM). The component has also obtained NSC's endorsement on a Boiler Best Practice programme because there are no fixed standards with regards to energy efficiency and maintenance for boilers in Malaysia.

ENERGY EFFICIENCY PROMOTION COMPONENT

Information is disseminated through the MIEEIP quarterly newsletter and to date 11 issues have been produced. Local case studies of factories that were audited by the MIEEIP are highlighted in the newsletter. A new website on MIEEIP is currently being developed. The component also facilitated the establishment of the Malaysian Association of Energy Service Companies (MAESCO) and the Malaysian Energy Professionals Association (MEPA), as well as the preparation for the respective accreditation schemes.

Networking has been established with the Department of Natural Resources of Canada and the Department of Energy, United States. These organisations will be included as links to the new website.

ESCO SUPPORT COMPONENT

To date, 32 energy service companies (ESCOs) have registered with PTM and they have been developed through five different programmes with the assistance of foreign (Canada, Europe, India and Thailand) and local experts. Four ESCOs have been selected to conduct energy efficient technology demonstration; the first was launched on April 7 for the wood sector. The development and training of ESCOs through workshops and seminars are an ongoing activity under this component.

ENERGY TECHNOLOGY DEMONSTRATION COMPONENT

The Master Energy Services Agreement (MESA) for the energy efficient technology demonstration programme under the ESCO concept for the wood sector component had been completed under this component. The second MESA for the cement sector is expected to be signed in the third quarter of 2003. The component has also identified eight potential projects from various sectors for the demonstration scheme under the normal approach (joint venture between the industries and PTM). The demonstration programme integrates the various components of the MIEEIP to provide a holistic approach in capacity building: the factory was identified from the energy audits under Component 2, the ESCO selected and developed under Component 5 and the financial mechanism developed through Component 8.

LOCAL ENERGY EFFICIENT EQUIPMENT MANUFACTURING SUPPORT COMPONENT

The MIEEIP has identified five equipment manufacturers (motor, boiler, fan & blower, pump, heat exchanger) who will be trained and educated on manufacturing energy efficient equipment. The team is organising a workshop for plant managers and supervisors as well as the equipment manufacturers on the Boiler Best Practice programme.

FINANCIAL INSTITUTION PARTICIPATION COMPONENT

An energy efficiency project-lending scheme (EEPLS) has been established at the Malaysian Industrial Development Finance Bhd (MIDF). A total amount of RM8 million had been set aside to finance four demonstration projects under the ESCO concept. Loans with zero percent interest are being offered to finance 50 percent of the project costs for the other demonstration programmes as well as for local equipment manufacturers to produce energy efficient equipment.

Workshops and seminars are being organised for the financial institutions to disseminate information regarding the viability of energy efficiency projects.

OIL AND GAS SECTOR

The outlook for the oil and gas sector in Malaysia remains positive despite predictions from many experts that there will be very few major oil discoveries. A recent discovery of deep-water oil off the coast of Sabah state indicates an estimated reserve of 700 million barrels. This new discovery will prove to be a significant boost to the declining oil reserve of the economy. The Malaysian government has also stated that it will continue its policy of developing the country's hydrocarbon resources, with particular emphasis on the development of gas fields.

Many upstream and downstream development projects that were delayed as a result of the various economic slowdowns in previous few years have recently been completed or are due for completion this year or next. Between April 2000 and March 2001, six new downstream petrochemical plants were completed while two others were completed and commissioned by the end of 2002. As the wave of petrochemical plants in Malaysia has been completed so the focus of the industry has moved back to the upstream sector. Petronas, together with its foreign partners had invested RM10.41 billion between April 2002 and March 2003 in upstream developments. The oil and gas sector will therefore remain a high priority market for Malaysia

At January 2003, Malaysia's gas reserves stood at 89.0 trillion standard cubic feet. These reserves are expected to last for 35 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 2003, Malaysia's natural gas reserves at January 2003 ranked as the 13th largest in the world.

Petronas explores, 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. Of the approximately 500,000 square km of land and seabed available for oil and gas exploration in Malaysia, 205,500 square km is covered by PSCs. As of January 2003, exploration of the continental shelf had resulted in discovery of 123 oil fields and 218 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 4.8 billion barrels of oil equivalent as of 1 January 2003. 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; and
- 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 AND UTILISATION

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 (MoU) on 8 August 2002 to facilitate a Gas Sales Agreement (GSA) from South Sumatra to Malaysia. The GSA, is 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 petrol powered vehicle. More importantly, these NGVs significantly lower fuel expense.

Petronas' subsidiary, Petronas NGV Sdn. Bhd., signed a three-year 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.

RENEWABLE ENERGY (RE)

To reduce over 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 in the Energy Commission.

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.

The National Special Committee on Renewable Energy (SCORE) set up within the Ministry of Energy, Communication & Multimedia (MECM) to process applications from potential developers, to date (August 2003) has approved 50 applications from potential RE developers.

FISCAL INCENTIVES FOR RE

In Malaysia, Investors in RE generally qualify for direct tax incentives in the form of Pioneer Status or Investment Tax Allowance (ITA). Where the project activity is carried out in certain promoted areas of the country, companies are eligible for higher exemptions/ allowances under the Pioneer Status or ITA. For purpose of incentives, renewable energy resources include palm oil mill or estate waste, rice mill waste, sugar cane mill waste, timber/sawmill waste, paper recycling mill waste, municipal waste and biogas (from landfill, palm oil mill effluent, animal waste and others). The above incentives also apply to the use of hydropower not exceeding 10 MW and solar power.

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 (2001-2005), 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. CETREE's dissemination of information and training activities on RE & EE has been mainly focused in secondary schools, universities, energy professionals, and the general public. Partly through CETREE's efforts, EE & RE has now been incorporated in the education curriculum of secondary schools. CETREE has designed a two-credit course on RE and EE for universities students which has been approved by the USM senate. A mobile Exhibition Unit comprising an energy van and six knowledge kiosks pertaining to RE & EE has been created. The van is self sufficient using electricity from solar cells and the engine runs on palm oil or vegetable oil. With this van, CETREE brings practical knowledge on RE & EE to schools, teachers and the general public in Malaysia.

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.

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PETRONAS Group Results for the financial year ended 31 March 2003.

MEXICO

INTRODUCTION

Mexico is located in North America, bordering the United States to the north and Belize and Guatemala to the south. Mexico is one of the most populated economies in Latin America, with its total population of about 99.4 million, growing at an average of 1.6 percent annually in the last 10 years. Rapid urbanisation at the last turn of the 20th Century has brought at least 75 percent of its people in urban areas. Twenty nine percent of these urban dwellers have settled in the six metropolitan areas, the largest of which is Mexico. As of 2000, Mexico is home to 17.8 million people. The average real GDP growth rate (at purchasing power parity) was 1.7 percent from 1980 to 1995. The relatively slow growth was tempered by episodes of economic downturn such as those experienced during 1982, 1988 and 1995. The economy recovered rapidly to 5.5 percent between 1995 and 2000 (with a peak of 6.9 percent in 2000), only to contract by -0.3 percent in 2002 as US economy slowed down, bringing down further its growth to 0.9 percent in 2002.[7] The United States is Mexico's largest trading partner.

The Mexican economy seems to have started a new growth phase at the start of the second quarter of 2003. The Government hopes that in the next couple of years, it will be able to recover the jobs lost during the recession period of 2000-2002. The main policy objectives for the economy now are to restart production growth, and recuperate lost jobs and strengthen the development of isolated social groups. Economic and political reforms proposed by the present Administration are being discussed in Congress and are considered an important prerequisite to revitalize the economy and allow it to achieve sustained growth rates of 5 percent per annum in the not-too distant future.

Table 21 Key data and economic profile (2001)

Key data		Energy reserves**	
Area (sq. km)*	1,964,375	Oil (MCM)	2,734
Population (million)	99.42	Gas (BCM)	420
GDP Billion US$ (1995 US$ at PPP)	807.75	Coal (Mt) - Recoverable***	1,211
GDP per capita (1995 US$ at PPP)	8,125		

Sources: Energy Data and Modelling Center, IEEJ. * INEGI, Información geográfica. 2003. http://www.inegi.gob.mx

** As of January 2003. Anuario Estadístico 2003 PEMEX. For 2003, PEMEX uses the US Securities and Exchange Commission's definition for "proven reserves". *** As of January 2002.

ENERGY DEMAND AND SUPPLY

PRIMARY ENERGY SUPPLY

Total primary energy supply in Mexico was 151 Mtoe in 2001. Oil and gas (with contributions of 54 and 27 percent respectively) dominate primary energy supply with a combined share of 81 percent. The remaining fuel sources are hydro (5 percent), coal (5 percent), nuclear (2 percent), geothermal (1 percent), and other fuels (6 percent). "Other fuels" which include firewood,

[7] INEGI (2003).

continues to be an important source of energy in rural households, contributing 4 percent to the total primary energy supply.[8]

OIL

The oil industry plays a crucial role in the economy, accounting for about one third of government revenues. PEMEX, Mexico's state oil company is the third largest crude oil producer in the world after Saudi Aramco and Iran's NIOC. In 2002, total Mexican oil production was 158 Mtoe, 1.6 percent more than the previous year. PEMEX is also the 6th largest oil company in the world in terms of revenue, and by law is the sole provider of oil services in Mexico from upstream exploration to final distribution. Proven oil reserves in January 2003 were the 13th largest in the world, totalling 2,734 MCM (including condensates and plant liquids).

Around 55 percent of the crude oil produced in Mexico is exported, and most of the exports go to the United States, its largest customer. In 2002, total exports were 2.7 percent lower than the year before as a result of Mexico's policy to support worldwide supply reductions in order to stabilise oil prices in the international market.

PEMEX owns six major refineries that are currently being upgraded to increase output volume and improve the quality of gasoline and distillate production. Mexico imports finished oil products and in 2002 total imports of oil products amounted to 243 Million barrels/day or 27.5 percent less than in the previous year.

NATURAL GAS

Proven natural gas reserves were 420 BCM in January 2003. Indigenous production of natural gas in Mexico was 4.4 Bcfd in 2002, 1.9 percent less than the year before. The reduction in production was due in part to the bad weather which temporary closed the gas wells in the Gulf of Mexico. The reduction was also caused by other factors like delays in the commissioning of production projects, maintenance work, and a decrease in the demand for electricity. Domestic gas production in Mexico is projected to reach 7.7 Bcfd by 2010 despite the diminishing exports, reaching only 4 Mcfd in 2002. Imports have increased considerably to 102.7 percent from the previous year of 592 Mcfd. Mexico is now a net gas importer (mainly from the United States

Natural gas consumption is expected to grow substantially in the coming years, driven mostly by electricity generation. According to the Mexican Energy Secretariat, the total gas consumption will grow annual average rate of 7.4 percent between 2002 and 2011, while the demand from the power sector grows at a rate of 12.6 percent annually during the same period.[9] In anticipation of this growth, plans are underway to increase domestic supply by focusing investments on gas exploration and production activities and transportation infrastructure. However, because of the huge investments requirements and restrictions on the budget of PEMEX, the Government will expect that, in the medium term, domestic natural gas demand will continue to grow more rapidly than production. Imports therefore are expected to account for as much as 18 percent of domestic demand by 2011.

COAL

The total coal supply in 2001 was 7.6 Mtoe and has accounted for around 5 percent of the total primary energy in the same year. The total coal resources was 1,211 Mt., most of which are located in the northern part of Mexico. Around 70 percent of the coal recoverable reserves are anthracite and bituminous types, while the remaining 30 percent are of the low heating value lignite and sub-bituminous classes.

Most of the coal in Mexico are used for steel production and electricity generation. To complement the growing demand of the sectors, Mexico is compelled to import additional coal

[8] Secretariat of Energy, Mexico (2002a).

[9] Secretariat of Energy, Mexico (2002c).

from the United States, Canada and Colombia. The largest coal producer in Mexico is Minera Carbonífera Rio Escondido (MICARE), owned now by a US-based Mission Energy.[10]

ELECTRICITY

In 2001, the electricity generation capacity in Mexico reached 42,410 MW, 87 percent of which is owned by the two state-owned electricity monopolies? Autogenerators, IPPs, and co-generators own the remaining 13 percent.

Electricity generation has increased rapidly over the past decade at an annual average rate of 5.2 percent. Total electricity generation in 2001 reached 210 TWh, of which 193 TWh came from Mexico's two public utilities and 17 TWh from IPPs and private producers. Electricity generation is expected to increase by an average 5.6 percent per year between 2002 and 2011. Fossil fuels contributed 69 percent to the total electricity produced in 2001, while hydropower contributed 14 percent, coal 9 percent, nuclear 4 percent and geothermal and wind power 3 percent.[11] For its future power generation mix, Mexico plans to have at least37 to 75 percent of its future additional generation capacity on natural gas combined cycles. Coal will probably account for 12 percent of the additional capacity.

Mexico has large potential reserves of renewable energy resources, although at present only hydropower and geothermal energy has been widely used. A total of 9,679 MW of hydropower and 837 MW of geothermal energy have so far been developed. The government has a policy to promote renewable energy. It includes, among others, plans for the continuing research and the introduction of favourable conditions for generators using these resources into its proposal for electricity market reform. Attention will be given to biomass and wind plants, and plans are underway to develop wind farms along the southern pacific coast, in the State of Oaxaca. Solar energy, in combination with other renewable sources including wind and biomass are currently being promoted as a power source for isolated rural communities, where extension of the national grid are too costly due to terrain conditions.

As much as 17,000 MW of capacity are believed to be readily available from wind, mini-hydro and solar resources. In the next ten years around 3,000 MW of new hydropower plants will be added to the generation pool along with 107 MW of geothermal plants.

Table 22 Energy supply & consumption for 2001

Primary Energy Supply (Ktoe)		Final Energy Consumption (Ktoe)		Power Generation (GWh)	
Indigenous Production	231,283	Industry Sector	26,977	Total	192,517
Net Imports & Other	-79,732	Transport Sector	38,211	Thermal	150,178
Total PES	151,551	Other Sectors	27,982	Hydro	28,041
Coal	7,612	Total FEC	93,170	Nuclear	8,801
Oil	84,957	Coal	1,813	Others	5,497
Gas	41,245	Oil	59,747		
Others	17,738	Gas	9,712		
		Electricity & Others	21,899		

Source: Energy Data and Modelling Center, IEEJ.

For full details of the energy balance table see http://www.ieej.or.jp/apec/database/selecttable.html

[10] EIA (2003).

[11] Secretariat of Energy, Mexico (2002b).

FINAL ENERGY CONSUMPTION

As a result of the periodic economic downturns, energy consumption has fluctuated significantly over the last twenty years. The average growth rate in energy demand was 2 percent between 1980 and 2000. Total energy consumption in 2001 was 93.2 Mtoe, a decrease of 3.3 percent relative to the previous year due to the negative growth in the economy experienced during 2001. Transport accounted for 41 percent of consumption in 2001, industry for 28 percent, the residential and commercial sectors for 21 percent, while agriculture and non-energy uses accounted for 3 and 6 percent respectively.[12]

POLICY OVERVIEW

The State's ownership of natural resources including oil, and its control over the oil and electricity industries, are principles embedded in the Political Constitution of Mexico. The Constitution defines "strategic" areas as those that are under the exclusive responsibility of the State and include among others: the ownership and production of radioactive minerals, oil and all other hydrocarbons, basic petrochemical processes, electricity and nuclear power generation.

This legal framework has historically restricted the participation of private investors in the energy sector. However, in the interests of modernisation of the national infrastructure and increased productivity the government in its "Energy Sector Program 2001-2006" recognised the need to liberalise energy markets to augment investment capacity, foster competition and to enhance energy quality and supply.

Modifications to the legal framework have now made the limited participation of private and foreign investors possible. Changes to the "Public Service Electric Energy Law" of 1992 have opened the door to private investment in the electricity industry to Independent Power Producers, co-generators, auto-producers and small (less than 30 MW) generators. Independent Power Producers can sell their energy to the State monopoly through power purchase agreement schemes. Since 1998, every new power generation facility has been constructed following this model.

In 1995, the Oil Regulatory Law was reformed to open the possibility to investors to construct, own and operate natural gas transport, distribution and storage systems. As well, the modifications make it possible now for private entities to import export and commercialise natural gas to final consumers.

Another modification to the Oil Regulatory Law in 1996 defines "basic" and "non-basic petrochemical compounds" and allows private investment and participation of up to 100 percent in new plants for the production of non-basic petrochemicals.

In the Liquefied Petroleum Gas (LPG) market, private participation had been allowed since the 1950's, but a new "LPG Regulation" published in June 1999 reorganised the industry into four areas and defined the participants allowed in each. Under the terms of this regulation, PEMEX continues to be responsible for first hand sales (sale of the original product), transportation by pipeline, and the operation of its production and supply plants. National and foreign private participation is allowed in transportation and storage, while final distribution and commercialisation was established as an exclusive area for national private investors.

Mexico is a major non-OPEC oil producer, and together with that organisation and other independent producers, it has been a main contributor to the stabilisation of crude oil market prices. Following the adjustments made by OPEC to its production levels in December, 2002 and January, 2003, Mexico adjusted its crude oil export platform to 1 million 880 thousand barrels per day beginning in February 2003.

[12] Secretariat of Energy, Mexico (2002a).

NOTABLE ENERGY DEVELOPMENTS

OIL AND GAS SECTOR DEVELOPMENTS

At present the oil and products sector in Mexico represents 1.4 percent of its Gross National Product. Exports account for 10 percent of the total national exporting activity and the oil and products sector provides 35 percent of federal government revenues. This heavy fiscal load imposed on the operation of PEMEX is in part the reason why in recent years the resources available for reinvestment have diminished, and as a result reserves have decreased and imports of refined products and petrochemical products have increased. The government has made a proposal for discussion by the Congress to change the tax structure to which the national oil company is subjected.

A “multiservice contract” investment scheme along the lines of those in use in Iran and Venezuela has been proposed and used on a few occasions to allow private parties to participate in exploration activities for oil and natural gas. In these contracts, PEMEX pays a set fee for services provided and retains ownership of the energy resources produced. This scheme, nevertheless, has faced strong political opposition from rival parties in Congress and has now raised doubts about its legality within the present Constitutional framework. The chances of this type of scheme being used again in the future are slim, save for further amendments to the Constitution.

LNG FACILITIES

In the medium term, the rapid growth in natural gas consumption will represent a big challenge for PEMEX. PEMEX is projecting a natural gas supply growth rate in the next 10 years of about 5.9 percent compared to a growth of 7.4 percent for consumption, resulting in a deficit 1.627 Bcfd of the fuel in 2011 or 18 percent of domestic demand. Restrictions on the availability of funds for reinvestment on the required schedule means that alternative supply sources have to be found. PEMEX’ strategy to cover the expected demand at present is based on focusing funds to the exploration of new resources and to promote the construction of importing LNG facilities.

As of August, 2003, the Energy Regulatory Commission had already granted 4 permits for LNG regasification and storage facilities. One to be located on the Gulf Coast of Mexico and three on the Pacific coastal area on Baja California, near the United States border. LNG regasification capacity of the four terminals will approximately be 4 Bcfd and will have a cost of around US$ 2.5 Billion. They are expected to be online between 2006 and 2007.

RENEWABLE ENERGIES

The State of Oaxaca in the south Pacific coast has some of the best wind resources in Mexico. The Federal Electricity Commission, one of Mexico’s two public electric utilities, has a 1.6 MW testing plant in the area since 1994 and is now considering the installation of a 50 MW plant to be operational by 2005. With the sponsorship of USAID and the expertise of the USDOE’s NREL laboratory, the State Government recently mapped the region to make a precise quantification of its wind resources and promote the technology among national private investors. The mapping process displayed optimistic results and is currently under evaluation to finalise the precise estimation of the wind potential.

POWER SECTOR DEVELOPMENTS AND RESTRUCTURING

A second electricity industry restructuring bill had been submitted to Congress by the present Administration and has still been under discussion in Congress for the better part of the last year. For many years the state power companies Comisión Federal de Electricidad (CFE) and Luz y Fuerza del Centro (LFC) enjoyed monopolies in the electric power sector until the first legislative reforms in 1992 made it possible for independent power producers (IPPs), auto-producers and co-generators to sell power. However 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 at an accelerated pace over the next two decades at a moment when infrastructure investment by CFE is expected to decline.

The investments needed for the electricity sector for the period 2002-2011, as estimated by Mexico's Energy Secretariat, amount to US$ 59 Billion., Around US$ 22 Billion are required for additional generation capacity and US$ 27 Billion for added transmission and distribution infrastructure. Appropriating these funds will be a challenge for the federal budget according to the Energy Secretariat, and so finding alternatives for financing is a necessity.

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 electricity price subsidies so that they are funded through the federal budget rather than from the companies' revenue.

Present discussions in Congress centre around on whether or not the principles of State ownership and control stated in the Constitution should be modified to allow for the proposed changes, and the extent of the control to be exercised by the State. Opposition parties have formed a majority block that is intent on not allowing the privatisation of current State-owned assets. It seems likely that an agreeable reform will limit private participation to newly constructed assets and will ensure a strong controlling role by the State.

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NEW ZEALAND

INTRODUCTION

New Zealand is a small island nation in the southern Pacific with a population of approximately 3.9 million in 2001. GDP has grown by an average of around 2.8 percent per annum in the eleven years to 2001 (since 1990) reaching about US$ 70.6 billion in 2001.

New Zealand had modest energy resources including 12.7 MCM of oil, 48 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 (2001)

Key data		Energy reserves*	
Area (sq. km)	268,680	Oil (MCM)	12.7
Population (million)	3.85	Gas (BCM)	48
GDP Billion US$ (1995 US$ at PPP)	70.59	Coal (Mt) - Recoverable	8,600
GDP per capita (1995 US$ at PPP)	18,340		

Source: Energy Data and Modelling Center, IEEJ.

* Ministry of Economic Development (New Zealand) as at 31 December 2001.

ENERGY DEMAND AND SUPPLY

PRIMARY ENERGY SUPPLY

New Zealand's total primary energy supply in 2001 was 18,597 ktoe. A variety of energy sources are used to meet these needs comprising of oil (33 percent), gas (29 percent), geothermal (13 percent), hydro (12 percent), coal (5 percent) and others (8 percent). Self-sufficiency in 2001 was just over 83 percent.

New Zealand was 32 percent self-sufficient in oil in 2001, down from 34 percent in 2000. New Zealand's estimated remaining crude oil and condensate reserves comprise the Maui field (containing 59 percent of reserves at December 2001), the Kapuni, Kupe, McKee and five other smaller fields. Production of crude oil and condensate was 1,509 ktoe in 2001, all from the Taranaki region. Crude oil and condensate production increased steadily since the early 1970s, but there have been significant decline in production over the last few years, following a peak in production in 1997. This is 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 2001 was 5,319 ktoe, up by 5 percent over the production of 5,057 ktoe in 2000. There were nine oil and gas fields in 2001, with the Maui field continuing to dominate (74 percent of gross gas 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 2006 or 2007 after a significant downwards revision of recoverable reserves in early 2003. As natural gas becomes scarcer and deliverability declines, rising prices are likely to mean that its use will be traded to higher value uses. Therefore, its use as feedstock for methanol production, recently comprising around 40 percent of consumption, will fall. Electricity generation will become the dominant use, with the balance being distributed to industrial and residential 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. Both coal production and exports were at all-time highs in 2001 with production of about 2,470 ktoe and exports of about 1,360 ktoe.

In 2001, New Zealand generated 39,595 GWh of electricity. Around 67 percent of generation was from renewable resources, a relatively low share due to water shortages. Hydro at 54.6 percent was the most important source of generation, although its share can usually be expected to be well above 60 percent. The thermal share was consequentially high at around 34.7 percent, geothermal was around 7 percent and others at around 4 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 (38.3 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 45percent of electricity demand in 2001. The residential sector consumed around 34 percent with the commercial sector consuming the balance of 21 percent.

New Zealand is likely to exhaust its existing gas reserves in the next 11-12 years depending on the rate of gas usage. Since natural gas imports are not feasible (except possibly 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 gain greater shares over the next 10 to 15 years.

Table 24 Energy supply & consumption for 2001

Primary Energy Supply (ktoe)		Final Energy Consumption (ktoe)		Power Generation (GWh)	
Indigenous Production	15,492	Industry Sector	3,447	Total	39,595
Net Imports & Other	3,105	Transport Sector	4,896	Thermal	13,736
Total PES	18,597	Other Sectors	5,025	Hydro	21,621
Coal	900	Total FEC	13,369	Nuclear	-
Oil	6,209	Coal	920	Others	4,238
Gas	5,319	Oil	5,824		
Others	6,169	Gas	2,708		
		Electricity & Others	3,916		

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

FINAL ENERGY CONSUMPTION

Total energy consumption was 13,369 ktoe in 2001. Consumer energy is dominated by oil, comprising 5,824 ktoe per annum (44 percent), with electricity 2,994 ktoe (22 percent), gas 2708 ktoe (20 percent), coal 920 ktoe (7 percent) and renewables such as geothermal, wastes and wood making up the remainder (7 percent).

Transportation (domestic) is the largest end use accounting for 37 percent of final consumption. The bulk of petroleum products used in New Zealand are consumed by this sector. The industrial sector is next with 26 percent and others which comprises of residential /commercial sector, non-energy sector, and agricultures sector consumes the remaining 37 percent.

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.

In the last year or so, it has become apparent that New Zealand faces potential supply problems in respect of natural gas and electricity. For electricity, the longer term issues are due, in part, to the declining gas supplies as well as factors such as protracted planning and regulatory processes and a rising supply (cost) curve. Short-term issues in the electricity sector relate to the fact that, in the fall of 2003, New Zealand faced its third electricity shortage in twelve years. Policies are being developed to address all these issues.

In general, the incumbent government favours industry self-regulation over government imposed regulations and interventions. In the power industry, sector participants were given the opportunity but were unable to agree upon a structure and governance for a self-regulatory body and so, the government has established an Electricity Commission.

NOTABLE RECENT ENERGY DEVELOPMENTS

ELECTRICITY

As mentioned above, the fall of 2003 saw the threat of electricity shortages in New Zealand. The shortages were caused by low rainfall and inflows into New Zealand's hydro-dominant generation system[13]. The threat of shortages resulted in high and volatile (spot) prices to the consternation of consumers, notably some industrial users who curtailed production when high power prices made production unprofitable. Voluntary demand restraint was called for with some effect. And as things turned out, sufficient rainfall and inflows meant that any shortages in the winter were averted.

The latest threat of shortage was the third in twelve years and follows one in 2001. The dry year problem was exacerbated by the gradual elimination of the supply surplus that had arisen from the around 1300 MW, or roughly 10 years' supply capacity, commissioned between 1996 and 2000. The impending depletion of the Maui gas field around 2007 and rising electricity demand associated with robust economic growth has also contributed to creating some urgency with regard to longer-term supply adequacy. A rising supply (cost) curve and the pressure for additional renewables continue to make hydro and wind power more competitive.

Early in 2003 significant announcements to the electricity sector designed to deliver long-term electricity supply security were made. The most significant of these was the Government's announcement of a seven-member Electricity Commission.

The Commission will be responsible for managing the electricity sector so that electricity demand can be met in a 1-in-60 dry year without the need for national power conservation campaigns. It will do this by contracting with generators for the provision of dry year reserve

[13] Currently, normal hydro operations provide somewhat over 60 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.

generation capacity and fuel. These reserves will be withheld from the market until dry years, when they will be released into the market at a high price. The cost to electricity consumers of securing adequate reserve generation is estimated at under half a cent per unit of electricity. The cost is low because the reserve generation is expected to comprise new plant with relatively low capital costs, plus heavily depreciated old plant. The fuel, though costly, will be rarely used.

The Commission will have the power to recover the cost of reserve generation in the manner it judges to be most efficient, for example through a levy. The necessary portfolio of reserve generation is expected to be built up within about three years.

ELECTRICITY DEMAND MANAGEMENT

To improve both electricity supply security and end-use efficiency, the government, in May 2003, announced additional funding for two programmes to be managed by the Energy Efficiency and Conservation Authority (EECA). One is of NZ$2.9 million for Demand Exchange programmes that are expected to save around 350 GWh (around 1 percent of demand) per year by 2005/06. The other is of NZ$1.64 million in 2003-2005 for an expanded energy audit programme covering around 10,000 GWh, around 30 percent, of consumption, that is expected to save 250 GWh, or 2.5 percent of this consumption, in 2005/06.

RENEWABLE ENERGY AND ENERGY EFFICIENCY

In the government's 2003 Budget presented in May, small amounts of funding, also to be managed by EECA, have been allocated to accelerate the uptake of (non-traditional) renewable energy and improve energy efficiency. NZ$1.2 million has been allocated to providing insulation in low-income homes, NZ$200,000 has been committed to the Solar Hot Water Grants scheme and the NZ$1 million Crown Energy Efficiency Loan scheme has been doubled to fund public sector organisation' energy efficiency projects with the loans being repaid from energy costs savings.

NATURAL GAS

The Government initiated a wide-ranging review of the gas sector in February 2001. A draft Government Policy Statement was released in November 2002, and after a period of consultation and comment, the final Statement "*Development of New Zealand's Gas Industry*" was released on 28 March 2003. The package of changes contained in the Statement is designed to enhance efficiency and reliability in gas production and transportation, and improve fairness for gas customers.

The Government's objective for gas is to "*ensure that gas is delivered to existing and new customers in an efficient, fair, reliable, and environmentally sustainable manner*".

As it had for the power sector, the Government announced that it favours industry-led solutions where possible, but is prepared to use regulatory solutions if necessary.

To enable the development of these industry-led solutions, the Government has invited the gas industry to establish a governing entity and decision-making process to manage the further development of gas market arrangements. The governing entity must develop a work programme that enables the development of efficient gas market arrangements in a timely and effective manner.

The governing entity must be representative of all stakeholders, including consumers, and have an independent chair. Importantly the entity must have a majority of independent persons, appointed after consultation with the Minister of Energy. It must have the power to develop and enforce arrangements consistent with the Government Policy Statement, and must not operate in the interests of individual participants.

The Government has signalled that the initiatives it will require of the governing entity include:

- Improving arrangements for the wholesale trading of gas;
- Developing an open access regime for all transmission pipelines;

- Developing standard terms and conditions for accessing distribution pipelines;
- Developing model contracts for consumers;
- Developing standardised arrangements for customer switching; and,
- Establishing an independent system for handling consumer complaints.

The Government sees open access to the Maui pipeline (approximately 80 percent of New Zealand's gas supply comes from the Maui field) as having a critical role in promoting the efficient delivery of gas. The Government has signalled its wish to facilitate the process of amending the Maui contracts (in which the Government has a significant commercial interest) so that non-Maui gas can be transported though the pipeline.

The Government, as a party to the Maui contracts, has invited the companies involved to present it with a proposal providing for open access to the Maui pipeline.

There has also been debate in New Zealand over whether gas pipeline prices are excessive. For this reason the Government has requested the Commerce Commission, under section 56 of the Commerce Act to make recommendations on whether or not supply of gas pipeline (transmission and distribution) services should be controlled. The Minister has requested the Commission to complete the inquiry by 1 November 2004.

OIL AND GAS EXPLORATION / MINING

In 2001 there were 18 wells drilled in three petroleum basins. All of the wells were drilled onshore. The 2001/02 onshore and near shore Taranaki Bidding Round attracted 41 bids for 26 blocks on offer and resulted in 21 new permits being awarded in August 2002. In September 2002 the government opened the Deepwater Taranaki Bidding Round. Five blocks were placed 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 and a new Taranaki Bidding Round. As of November 2002 there were 69 onshore and offshore exploration permits in New Zealand.

There have been two new oil 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) and 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.

ENERGY EFFICIENCY

The National Energy Efficiency and Conservation Strategy (NEECS) was 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.

The Strategy is underpinned by 5 Action Plans that identify actions and allocate responsibility for carrying them out. The Action Plans are in the following areas: Buildings and Appliances (Residential/Commercial), Industry, Transport, Central and Local Government, and Energy Supply.

The methodology to measure progress towards the NEECS's targets has included establishing the base year for the targets and indices to measure progress. New Zealand's Energy Efficiency and Conservation Authority (EECA) is measuring and communicating progress by a national energy efficiency index. This index is being built up from a comprehensive programme of sectoral and sub-sectoral monitoring which includes the development of a number of key indicators for each sector. Some of the necessary monitoring information already exists, but further expansion is required. EECA is identifying data gaps, determining key monitoring indicators, and undertaking sector studies to fill data gaps. Sector studies undertaken during the past 12 months include local government, dairy, timber processing, and meat industry sectors.

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.

The National Energy Efficiency and Conservation Strategy (discussed above) is one of the framework's “foundation policies” along with the Growth and Innovation Framework; the New Zealand Transport Strategy (under development); the New Zealand Waste Strategy; climate change research; and a partnership with local government in addressing climate change at a local level.

The key measures and actions in the climate change policy include:

A charge to be applied to emissions from fossil fuels and industrial processes. The charge will approximate the international emissions price, but be capped at $NZ25[14] a tonne of carbon dioxide equivalent. It will apply in the Kyoto Protocol's first commitment period 2008-2012. Revenue from this tax will be recycled, for example through the tax system and into funding climate change projects and programmes. The government retains the option of introducing emissions trading as an alternative to an emissions charge if the international carbon market is functional and the price is reliably below the $NZ25 cap.

Provision of government incentives for climate change projects that will deliver defined reductions in greenhouse gas emissions, in any sector of the economy. Incentives might include money or the pre-allocation of emission units. The government will invite bids from firms or groups via a contestable process. To qualify, projects must go beyond business-as-usual plans.

Negotiated Greenhouse Agreements (NGAs) for firms and industries where there is significant risk to their international competitiveness. Negotiated Greenhouse Agreements would comprise a contractual commitment by the firm or industry to achieve international best practice in managing emissions, in return for exemption from all or part of the emissions charge.

Exemption for the agricultural sector's non-CO_2 emissions from any price measure (emissions charge or trading regime) in the first commitment period, provided the sector invests in research to identify options for reducing agricultural emissions. The government retains the option of imposing a research levy if the research effort falls below what is required.

Government retention of the sink credits and associated liabilities allocated to New Zealand under the Protocol in recognition of the carbon sink value of post-1990 forest plantings. These credits will be retained and managed by the government, at least for the first commitment period.

An amendment to The Resource Management Act (RMA) to remove regional councils' ability to directly control greenhouse gas emissions through resource consents and regional plans. This is because emissions are to be dealt with through national policies. Further RMA measures are being considered relating to prioritising renewable energy and adaptation to the effects of climate change.

[14] In 2002 one New Zealand dollar equalled US$ 0.462.

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PAPUA NEW GUINEA

INTRODUCTION

Papua New Guinea, an island nation in the South Pacific, is geographically located north of Australia and is comprised of more than 600 islands, several habitable ones including half of the main island of New Guinea with West Papua, Indonesia. PNG has a population of more than five million people who are spread across its total area of 462,840 square kilometres.

The PNG economy may be slow to recovering from current global economic slowdown influences. Current per capita GDP (US$ 2,385) is 5.8 percent lower than 2000 level (US$2,532). In 2001, real GDP at 1995 US dollars at PPP was estimated to be US$ 12.5 billion which declined by 3.5 percent from 2000 level. Inflation is around 13 - 15 percent.

Energy use per capita in PNG at 0.1 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 national economy. In 2001, the energy industry accounted for approximately 11 percent of domestic GDP, about 21 percent of total merchandise exports and employed about 1000 Papua New Guineans in both upstream and downstream operations.

Table 25 Key data and economic profile (2001)

Key data		Energy reserves*	
Area (sq. km)	462,840	Oil (MCM) - Proven	61.1
Population (million)	5.25	Gas (BCM)	397
GDP Billion US$ (1995 US$ at PPP)	12.53	Coal (Mt)	-
GDP per capita (1995 US$ at PPP)	2,385		

Source: Energy Data and Modelling Center, IEEJ.

* UN Energy statistics Yearbook and IMF Staff Country Report No. 99/66 Jul 1999.

ENERGY SUPPLY AND DEMAND

PRIMARY ENERGY SUPPLY

In 2001, PNG's net primary energy supply was 573 ktoe (down 42.1 percent from 2000). Light crude oil and petroleum products accounted for 60.9 percent, gas for 25.1 percent while hydro and other fuels comprised the remaining 14 percent. Around 79.2 percent or 2,184 ktoe of indigenous energy production is exported to other economies. An annual budget of US$ 20 million supports oil and gas exploration in PNG.

PNG has a small oil field, which has produced 100,000 bbl/day of light crude since 1992. As the field matures, production levels have begun to decline. The light crude is mainly for export. In September 2000, the government approved a Petroleum Development Licence for Moran Oil to begin production of 13,000 bbl/day by the end of 2000 to supplement the Kutubu project. Construction works for the oil refinery at Port Moresby (Napanapa) has commenced.

PNG also has a natural gas field with estimated reserves of 397 BCM. In 2001, a small amount of gas was produced (144 ktoe) for electricity generation – mainly for the gold mine at Porgera. PNG is still negotiating to sell this gas to Australia with approximately 100 –150 Petajoules per day per year as a base load.

As of 2001, total power installed capacity was 451.3 MW. PNG produced 2,638 GWh of electricity in 2001 (up 1348 GWh from 2000 or 104.5 percent increase from 2000). The sources of generation were hydro at 35 percent (down 4.7 percent from 2000) and thermal (gas and fuel oil) at 65 percent (gain of 4.7 percent at the expense of hydro). In 2001, 80.0 ktoe (up 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, the PNG Electricity Commission.

Table 26 Energy supply and consumption for 2001

Primary Energy Supply (ktoe)		**Final Energy Consumption (ktoe)**		**Power Generation (GWh)**	
Indigenous Production	2,756	Industry Sector	218	Total	2,638
Net Imports & Other	-2,184	Transport Sector	61	Thermal	1,708
Total PES	573	Other Sectors	86	Hydro	930
Coal	-	Total FEC	364	Nuclear	-
Oil	349	Coal	-	Others	-
Gas	144	Oil	147		
Others	80	Gas	-		
		Electricity & Others	217		

Source: Energy Data and Modelling Center, IEEJ.

For full detail of the energy balance table see http://www.ieej.or.jp/apec/database/selecttable.html

FINAL ENERGY CONSUMPTION

In 2001, total end use energy consumption in PNG was 364 ktoe (a decrease of 58 percent from 2000). By sector, industrial at 59 percent (a decrease of 46 percent over 2000) is the largest end use, followed by transport at 17 percent (a decrease of 72 percent over 2000), with agriculture and residential/commercial at 24 percent (a decrease of 64.6 percent over 2000). By fuel source, petroleum products accounted for 40 percent of consumption (a decrease of 81 percent over 2000), electricity and others for 60 percent (an increase of 115 percent over 2000) and natural gas appears to be zero.

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 PNG and the Civil Aviation Authority also use solar photovoltaics for power supply to telecommunication and navigational aids equipments.

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, energy policy matters are determined by the Department of Petroleum and Energy, and exploration and development of petroleum resources are overseen by the Ministry of Petroleum and Energy.

The Department of Finance and Treasury is responsible for setting prices or tariffs for electricity and petroleum products. The provincial governments work with the PNG Electricity Commission, the Energy Division of Department of Petroleum and Energy and/or private companies to organise new projects such as grid extensions or the development of small hydro and other renewable energy resources.

The PNG National Energy Policy Statement and Policy document has been referred back to the drawing board. Previous Acts of Parliament such as the Electricity Commission Act, gave authority to the PNG Electricity Commission for the generation, distribution and sale of electricity. The Petroleum Act of 1972 and the Oil and Gas Act of 1998 gave the Ministry and Department of Petroleum and Energy authority over the licensing and development of petroleum 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 diffusion of new and affordable renewable energy technologies. It also works closely with the PNG Electricity Commission to increase the available amount of electricity capacity as and when demand growth justifies it.

NOTABLE ENERGY DEVELOPMENTS

- The Rural Electrification Policy Document completed in June 2001 and still awaiting approval from the government, is aimed at improving rural access to electricity;
- The PNG to Queensland (Australia) Gas pipeline project is still under negotiation; and
- Inter Oil's 32,500 barrels per day oil refinery is progressing well.

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PERU

INTRODUCTION

Peru is South Americas third largest country. 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 a land area of 1,285,216 square kilometres. It is divided into three distinct geographic 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 2001 was US$ 114.3 billion while GDP per capita was US$ 4,340 (both in 1995 US$ at PPP). After experiencing a long slow recovery in the 90s, the economy bounced back in 2002, with an increase in GDP growth from just 0.2 percent in 2001 to 5.2 percent in 2002. Contributing to the growth were the increase in copper and zinc exports, particularly from Antamina mines, which has been in operation for one year as well as the successful economic recovery program supported by IMF.

Peru is now a net importer of energy. Of the total energy imported, more than 90 percent is crude oil used mainly as refinery feedstock since its 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 recoverable coal.

Table 27 Key data and economic profile (2001)

Key data		**Energy reserves***	
Area (sq. km)	1,285,216	Oil (MCM)	51.4
Population (million)	26.35	Gas (BCM)	245.1
GDP Billion US$ (1995 US$ at PPP)	114.34	Coal (Mt) - Recoverable	58.7
GDP per capita (1995 US$ at PPP)	4,340		

Source: Energy Data and Modelling Center, IEEJ.

* Proved reserves at the end of December 2001 data from Ministry of Energy and Mines, Peru.

ENERGY SUPPLY AND DEMAND

PRIMARY ENERGY SUPPLY

Peru's total primary energy supply (TPES) in 2001 was 11,032 ktoe, slightly less than that of 2000 , which was 11,047 ktoe. Oil still comprised the biggest share of TPES (62 percent), although its share decrease by 4.5 7 percent from 2000. As the Camisea gas has not come on stream , the share of natural gas only slightly increased from 14 percent to 15percent. With the favourable weather condition and the completeness of Machu Picchu hydro plant, hydro share increased from 13 percent in 2000 to 17.6percent in 2001. Coal share however decreased slightly from 6 percent in 2000 to 5 percent in 2001.

Peru has imported about 2,753 ktoe or 25 percent of its energy requirements (mostly oil from Colombia, Ecuador and Venezuela) in 2001, a 14.4 percent decrease from previous year's import of 3,215 ktoe.

Owing to a lack of new oil discoveries, production of crude oil has declined by 7 percent in 2000 and 3 percent in 2001 to an average of 96,000 bbl/d. However, in 2002, production has increased slightly to about 97,666 bbl/d. Total proven oil reserves in January 2003 was estimated at 53.2 MCM. Current production areas are located in the northern jungle along the Ecuador border, north eastern and central Peru and offshore. The government estimates that Peru will require US$ 165 million per year in drilling investments over five years to maintain its proven oil reserves. Unfortunately, initial exploration efforts in Peru's offshore coastal basins have yielded poor results, discouraging further investment by oil companies. Exploration drilling performed by Oil Company's decrease significantly for around 30 wells each in 2000 and 2001 to only 10 in 2002. Toledo administration had issued some measures to attract more investors.

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 of such capacity is being used. In 2001, Ecuador utilised the line to export oil. Oil is being sent via river barge to existing Peru's Pipeline, however there are plan to build a connecting pipeline to Norperuano.

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 for 2001

Primary Energy Supply (ktoe)		Final Energy Consumption (ktoe)		Power Generation (GWh)	
Indigenous Production	8,279	Industry Sector	3,112	Total	20,786
Net Imports & Other	2,753	Transport Sector	3,199	Thermal	3,171
Total PES	11,032	Other Sectors	2,520	Hydro	17,615
Coal	572	Total FEC	8,832	Nuclear	-
Oil	6,899	Coal	382	Others	-
Gas	1,614	Oil	6,826		
Others	1,947	Gas	-		
		Electricity & Others	1,623		

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

In December 2001, Peru's installed electric generating capacity reached 5,907 MW and about 75.3 percent of its population haveaccess to electricity. Hydropower and thermal share equally the electric generating capacity. However, hydropower produced 85 percent of the electricity in 2001 and 82 percent in 2002. Thermal plants include residual fuel oil, diesel, natural gas and coal.

In October 2000, a new north-south transmission line joined the former central-north (SICN) and southern (SIS) grids to form the National Interconnected Electrical System (SEIN). In 2002, of the 21,982 GWh of electricity generated in the economy, 98 percent was delivered through SEIN and the remaining 2 percent was delivered through several smaller isolated systems (SSAA). Of all the electricity traded in 2002, 52 percent were in regulated markets and 48 percent in free trade.

FINAL ENERGY CONSUMPTION

Between 1980 and 2001, final energy consumption in Peru increased by 48 percent while energy production fell by 29 percent. In 2001 final energy consumption in Peru amounted to 8,832 ktoe, of which transport consumed 36 percent, industry 35 percent and other sector 29 percent. Petroleum products dominated end use consumption, accounting for 78 percent of demand in 2001, decreased by 2 percent as compared with its share in 2000. While electricity share on final energy consumption was 18 percent and coal, 4 percent.

POLICY OVERVIEW

In 2002 Peru amended the constitution and began to decentralisa the structure of Government. The amendment mandated the creation of three level of government (National, regional and local) with political and economics autonomy. Regional elections were held in November 2002 and, the new administration took office on 1 January 2003. The decentralisation of government structure soon will follow by neutral decentralisation fiscal system.

To improve neutrality tax and increase tax base in 2002 Peru also reformed the tax policy and tax administration measure. Reform includes the removal of some VAT exemptions, increase in kerosene tax by 80 percent to partially reduce the differential with the tax on diesel, intensifying the control of tax collection and improvement in administration.

Peru's economy is becoming more and 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.

As part of Peru's effort to reduce air pollution in major cities and monetise the stranded natural gas, Peru has considered the development of the Gas to Liquid (GTL) plant that will exploit Talara and Northwest gas field. With support from Syntroleum, Peru's GTL project will be developed in 2 phases. Phase I involves the construction of a 5,000 barrel per day capacity GTL plant near Talara. The output will be expanded to as much as 20,000 to 40,000 barrel per day. The development of the GTL plant considerably support the plan to reduce sulphur content on diesel fuel specification to meet the proposed Clean Air Initiative for Lima-Callao.

NOTABLE ENERGY DEVELOPMENTS

PRIVATISATION PROGRAMME

The government that took office in July 2001 has stepped up its energy sector's privatisation activities (an effort which has slowed down under the two previous governments). While opposition claims 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 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 a delay or a reconsideration of its privatisation plans. In January 2003, the Government also postponed the privatisation of Yuncan hydro, as it failed to gain support from its local government.

But, the Government also gained some success in the privatisation. In July 2001 hydro generator Electroandes S.A.with a total capacity of 183 MW was successfully sold. In June 2002, two transmission companies Etecen and Etesur were also successfully sold to Colombian companies Interconexion Electrica, Traselca and Empresa de Energia de Bogota. Etecen operates 4,398 km lines and 29 220/60kV substations with a power transformation capacity of 1,503 MVA. The company responsible for transmission of electricity on the coast, in the central highland and northern Peru, which consume 60 percent of the electricity generated in Peru. Etesur operates 907 km of 138 kV transmission line and 13 substations with a power transformation capacity of 267 MVA for the coast and highland of southern part of Peru.

ADVANCES IN THE CAMISEA GAS PROJECT

Camisea gas was discovered by Shell in 1986, however the development just started in 2000 with the establishment of the Special Committee of Camisea Project (CECAM). CECAM divided the Camisea development into two projects, upstream and downstream. A consortium headed by Argentina Company Pluspetrol SA and consisting of Hunt Oil, SK Group and Tecpetrol awarded the 40 years contract to develop the upstream project. A 33 years contract for the downstream project consist of transportation gas from Camisea to Lima, Transportation gas liquid (condensate) to coat and distribution of gas in Lima and Callao was awarded to Traportadora de Gas del Peru (TGP). TGP, a consortium made up of Techhint, Pluspetrol, Hunt Oil, Sonatrach, SK Corporation and Tractebel will build two pipelines, one for natural gas (714 kilometres) and another for condensate (540 kilometres The pipelines are expected to deliver 250 MMSCFD of natural gas expandable to 729 MMSCFD by 2015 and 70,000 bpd condensate, with the first delivery expected to begin in August 2004.

In 2002, another additional downstream project, a 30 years concession for the construction of and operation of gas distribution network in Lima and adjacent port Callo was awarded to Tractebel. The distribution lines consist of 37 miles of distribution lines that will deliver gas to industries and power generators around Lima.

The total investment required in developing Camisea was predicted to reach about US$ 1.6 billion. The Peruvian Government and Camisea Company have been trying to secure a loan from US Exim Bank and Inter-American Bank (IDB). But due to the strong pressure from Environmental Groups the US Exim Bank rejected the US$ 214 million loan on 28 August 2003. However, on 10 September 2003 IDB has approved the US$ 135 million loan for the project. The loans consist of a US$ 75 million loan from ordinary capital and a US$ 60 million syndicated loan. TGP intends to issue US$ 200 million bond for additional funding.

Pluspetrol believes that Camisea could yield as much gas as the fields in neighbouring Bolivia, where recent exploration and development activities have uncovered reserves of *3.68 BCM natural gas and 95 MCM condensate*. 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 that 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 trunk line 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.

POWER GRID

Peru has been in the process of integrating its power grid with Columbia and Ecuador. Those three countries signed the agreement in September 2001 and April 2002. The integration will possibly expanded to Andean Community common electricity market, which will increase the efficiency of the market. The first inter-countries electricity sales will begin in 2004, when Peru starts exporting electricity to Ecuador. Currently, a US$15 million 35 miles transmission line and a US$30 million continues AC substation that allows the transmission line to transport 150 MW in both direction is being built. The capacity of the lines will be increased to 250 MW. The facilities will enable Peru to sell its excess hydropower during the rainy season to Ecuador.

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. To encourage investors, government has approved more attractive new fiscal terms in May 2003. There are two options that can be selected at the point of commerciality. First is, royalty based on production level, with royalty varying between 5-20 percent. Second, royalty with fixed component of 5 percent and variable component (up to 20 percent) depending on a measure of project profitability, paid after investment recovery. These new schemes consider a reduction of up to 30 percent royalty from the previous. In addition, Peru's government shall provide for a more flexible environment for investors to work, in which case the economies will provide the investor the right to market hydrocarbon freely, allow free capital flow inside or outside the economies, design work program in more flexible scheme and applies an international Arbitration on resolving disputes.

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THE PHILIPPINES

INTRODUCTION

The Philippines, located in the western rim of the Pacific Ocean, is domicile to 78.32 million Filipinos of various ethnic origins spread over a land area of about 300,000 square kilometres, carved up into 7,107 islands and islets. Luzon, the largest among the island groups, accounts for more than half of the population. North of the Philippines is Chinese Taipei and in the south, the Indonesian archipelago.

Despite the global and local security threats and political uncertainties, the Philippines' domestic economy laboured assiduously to overcome its difficulties. Gross Domestic Product (GDP) in 2001 grew by 3.4 percent at US$291.77 billion {1995 US$ at 1995 purchasing power parity (PPP)} while its GDP per capita posted a low of US$3,725 (1995 US$ at PPP). The economy's energy consumption per capita of 0.2 toe is still one of the lowest in the region.

The resilience of the Philippine economy plays an important role in the world energy market as it is eyed by many as a growing consumer (a net importer) of energy, particularly for power and a promising market for foreign energy companies.[15] In the long term, it may turn out to be significant natural gas producer or an LNG importer.

The Philippines' indigenous energy reserves are relatively 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. It however boasts of a geothermal resource that could make the economy the world's largest producer and user of geothermal energy for power generation. Other renewable energy resources (solar, wind, biomass and ocean) are theoretically estimated to have a power generation potential of more than 250,000 MW.

An effort to limit oil and coal imports to reduce the economy's dependence on imported energy has led to the prioritised and expanded use of natural gas for power generation.

Table 29 Key data and economic profile (2001)

Key data		**Energy reserves***	
Area (sq. km)	300,000	Oil (MCM) - Proven	24
Population (million)	78.32	Gas (BCM) - Proven	70
GDP Billion US$ (1995 US$ at PPP)	291.77	Coal (Mt) - Recoverable	317
GDP per capita (1995 US$ at PPP)	3,725		

Source: Energy Data and Modelling Centre, IEEJ. * Philippine Department of Energy (DOE).

As of 2002, proved reserve is 2.5 tcf or 70 bcm; 107 BCM is the total gas reserves which is classified into proved and unproved.

ENERGY SUPPLY AND DEMAND

PRIMARY ENERGY SUPPLY

In 2001, the total primary energy supply (TPES), excluding traditional fuels, amounted to about 32.7 Mtoe. The economy imports about 60 percent of total energy supply, the remainder was

[15] Philippines Country Analysis Brief, Energy Information Administration (EIA), 2002

supplied through domestic production of indigenous resources which amounted to around 13.2 Mtoe. Main energy sources were oil (49 percent), geothermal (35 percent), coal (13 percent), and gas (4 percent[16]). Gas, which contributed only around 0.087 Mtoe in 2000, has increased to 1.151 Mtoe, due mainly to the coming on-stream of the Malampaya gas field in October 2001. The average oil production up to early 2001 was only about 1,000 bpd, but by October 2001, production has increased 20-fold due to the development of the deep-sea condensate deposit in the gas and oil rich Malampaya field. However, this production is still only around 5 percent of the current demand of about 356,000 bpd. APERC projected that oil consumption will increase by 4.1 percent annually as demand in most sectors increase as a result of the healthy economic growth.

Almost all of the economy's total coal requirement is supplied through importation. Coal importation in 2001 has increased by 11.5 percent, or .787 Mt more than the volume reported in 2000. Bulk of these imports came from China (41.2 percent) and Indonesia (41 percent), while the rest were supplied from Australia (14 percent) and Viet Nam (3.7 percent[17]).

Historically, the Philippines coal industry has been heavily supported by regulations. However, with the entry of the World Trade Organisation (WTO) regulations, the Philippines was required to lift its import restrictions. This and other factors, including a switch (away from coal) to gas for electricity generation and opposition from pressure groups, are seen to most likely affect a decline in the importance of the domestic coal sector.

The government has announced that many coal-fired power plants will be converted to natural gas, including the 600 MW Calaca plant located south of Manila. To cushion its impact on the sector, government has encouraged alternative uses for the domestically produced coal. According to DOE, plans are underway for three new smaller-scale "clean coal" power plants (about 50 MW each). DOE expects these completed by 2005.

The commissioning of the natural gas fired power plants in October catapulted the economy's natural gas production to more than a thousand times, from 0.087 Mtoe in 2000 to 1.51 Mtoe. Following the success of the Malampaya project, more natural gas supply is expected as more areas are opened for prospective oil and gas developers.

Electricity production in the Philippines was about 54,455 GWh in 2001. Bulk of this generation came from thermal power plants, mostly run on coal and fuel oil (54 percent), geothermal (33 percent), and hydro (13 percent). Total installed power generating capacity is around 13,402 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.

Table 30 Energy supply & consumption for 2001

Primary Energy Supply (Ktoe)		Final Energy Consumption (Ktoe)		Power Generation (GWh)	
Indigenous Production	13,196	Industry Sector	3,594	Total	54,455
Net Imports & Other	19,530	Transport Sector	8,784	Thermal	29,503
Total PES	32,727	Other Sectors	4,929	Hydro	7,104
Coal	4,280	Total FEC	17,308	Nuclear	-
Oil	15,904	Coal	809	Others	17,848
Gas	1,151	Oil	13,133		
Others	11,392	Gas	-		
		Electricity & Others	3,366		

Source: Energy Data and Modelling Centre, IEEJ.

[16] Total is 101 percent.

[17] Total is 99.9 percent.

For full detail of the energy balance table see http://www.ieej.or.jp/apec/database/selecttable.html

The Philippines Energy Plan indicates that between 2003-2007, the economy's total primary energy consumption is expected to grow at average rate of 5 percent per year and may rise further to 5.8 percent between 2008-2012.

FINAL ENERGY CONSUMPTION

Final energy consumption was about 17.3 Mtoe in 2001. Half of the economy's energy supply was consumed by the transport sector, due mainly to oil making up more than 76 percent of the demand. Residential, commercial and other sectors has consumed up to 28 percent mostly for electricity while the remaining 20 percent was taken up by industrial sector, utilising coal for power generation, industrial direct process, small end-use household fuel and briquetting.

ENERGY POLICY OVERVIEW

The major energy reforms and developments being carried out in the Philippines include the reduction of the economy's dependence on imported energy (oil and coal), restructuring and deregulation of the electricity sector to improve efficiency (and attain the highest quality of service), provide fair and reasonable energy prices, and wider access to electricity supply.

The Philippines Energy Plan (PEP) 2003-2012 is set to achieve the following targets: to maintain an average self-sufficiency level of 50 percent by intensifying the development, exploration and use of the economy's indigenous energy resources (i.e. natural gas, coal, geothermal, hydro and other renewable energy) and diversifying its use in the power, industrial and transport sectors; full implementation of the provisions of RA 9136 or the Electric Power Industry Reform Act of 2001, monitoring and reviewing sector pricing policies to ensure transparency and improve system efficiency; and full energisation of the remaining un-electrified villages by 2006.

The government has issued a natural gas policy framework for its emerging gas industry. As facilitator, government shall see through the development of the domestic natural gas resource and ensure its competition with imported gas. Natural gas prices will however remain regulated in areas where there are no competitive fuels.

UPSTREAM OIL

The development of the economy's domestic oil supply depends heavily on international oil companies' willingness to invest in high-risk ventures like oil exploration and development. To further encourage investment in the oil sub-sector, the government has undertaken a resource assessment study, Philippine Petroleum Resource Assessment (PhilPRA), and complemented this with a promotions project, Philippine Petroleum Exploration Investment Promotion (PhilPRO) to publicise PhilPRA's results through international campaigns or road shows. The Department of Energy (DOE) has initiated a "bidding round system" to award exploration contracts to the applicant with the best work program proposal including its technical and financial capability.[18] Forty-six contracts are up for bid and proposals are expected to pour in until early 2004. It also plans to review its current service contract system, improving and adding more incentives to investments, to draw more prospectors in petroleum exploration.

DOWNSTREAM OIL AND REFINING

The past five years of the implementation of Republic Act No. 8479 or the Downstream Oil Industry act of 1998 strengthened the government's proactive role in setting policy direction that

[18] The First Philippine Public Contracting Round (PCR-1) will be opened in 2003 where forty six (46) contract areas will be offered to cover shallow to ultra deep water areas close to oil discoveries and producing fields in Northwest, Southwest and Eastern Palawan, Sulu Sea and Reed Bank. http://www.doe.gov.ph, 2003

would ensure consumer protection and more private sector participation. The promotion of fair trade practices, security of domestic oil supply, product quality and facility standards, quality and environmental protection are some of the concerns addressed by these policies.

The deregulation of the oil industry resulted to the interplay of market forces in the local market particularly on supply sourcing and pricing of petroleum products, both in bulk and retail. This paved the way for the new players to participate in a more liberal investment environment, thus increasing the degree of competitive pressure and eventually improve efficiency resulting in better quality of products and services and market-driven oil prices.

The competition brought in by these new players have resulted in better quality in terms of product and facilities, improved service at the gasoline stations, and a shift to a new image of service stations providing amenities within the facility's premises.

The implementation of the law does not mean total absence of regulations in the industry. Government controls are still necessary to guarantee the full benefits of deregulation especially in fuel quality, safety, consumer protection and fair trade practices. To supplement the rules and regulations implementing the deregulation law, circulars were issued, such as the Guidelines for Registration and Incentives Availment of the Downstream Oil Industry, Prior Notice on price Adjustments, Compliance with the Clean Air Act, Rules and Regulations Governing the Retail of Liquid Petroleum Products, etc.

NATURAL GAS

The Malampaya Gas-to-Power Project (MGPP) signified the birth of the natural gas industry in the Philippines. A DOE Circular 95-06-006 issued in the late 1990s provided the guidance for the integration of natural gas into the economy's energy supply mix. The Circular further 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 of the 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 the promotion of the 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 actively reviewing existing policies and carrying out structural reforms particularly in the power and downstream oil and gas sectors.

DEVELOPMENT OF THE NATURAL GAS INDUSTRY

Natural gas in the Philippines was discovered in 1989 by Occidental Philippines Inc. (Oxy). Although not the first discovery[19], the Camago well had exposed some promising signs. A year later, Oxy's exploration contract was converted into a service contract (SC38), with Shell Philippines Exploration B.V. (SPEX) farming-in half of its interests. Four more years of successive drilling by SPEX has led to the discovery of the Malampaya gas field in 1992, and after two more years, SPEX finally ascertained proven recoverable reserves of about 2.5 trillion cubic feet (TCF) of gas and 85 million barrels (MMB) of condensate. Finally, in 1998, the Malampaya gas field was declared a commercial find, with SPEX acquiring full ownership of SC38. A consortium was then

[19] In 1980, the Philippine National Oil Company - Exploration Corporation (PNOC-EC) discovered natural gas in Isabela, Northern Luzon sufficient to fuel at least 3MW of electricity.

formed with Texaco Philippines, Inc. (now Chevron Texaco) and the Philippine National Oil Company Exploration Corporation (PNOC-EC).

In a little over three years, the project was completed, landing gas for power plant commissioning and commercial operations in October 2001and January 2002, respectively.

The economy expects to gain at least US$8.1 billion (over the life span of the project) in economic benefits and foreign exchange savings of approximately US$13 billion from this project.

DOWNSTREAM NATURAL GAS

The DOE, through Executive Order No. 66, was mandated to lead the government's effort in ensuring the establishment of a robust natural gas industry. Taking into account the lack of an integrated law and a comprehensive set of regulations governing the industry, and the privatisation of the state-owned transmission and generation companies (the main or start-up market/application of natural gas), the DOE has initiated and formulated the policy and regulatory framework for natural gas.

In August 27, 2002, the DOE issued the Interim Rules and Regulations governing the transmission, distribution and supply of natural gas (Gas Rules). The Gas Rules are designed to, among others, maximise the economic efficiency in the development of the Philippine downstream natural gas industry, achieve the most efficient use of natural gas facilities and ensure the integrity and security of supply and reasonable return on investment.

While it is envisioned that government was to lead the development of the upstream and downstream sectors, the financing, construction and operation of the downstream natural gas infrastructure shall be left to the private sector. The government will limit itself in the formulation of strategies and programs favourable to the industry's growth and the efficient management of strategic gas infrastructures.

NATURAL GAS FOR POWER

The Philippines is anticipating a rise in electricity demand of about 7,150 MW[20] in the next ten years, and 4,200 MW of such capacity could be from natural gas. The government has envisioned a network of physical infrastructure necessary to bring natural gas to candidate plants (for conversion or greenfields) and or anchor loads. Candidate plants for initial conversion are the 950 MW Sucat thermal plant located in Metro Manila, and the 600 MW Limay thermal plant in the Bataan Peninsula. Additional natural gas plants of midrange capacity will be installed beginning 2007.

To bring the natural gas into these areas, the government has initially planned to establish the following integrated physical infrastructure network:

- A high-pressure gas transmission pipeline from Tabangao, Batangas to Metro Manila (BatMan 1), of 80 to 100 kilometres in length, that will serve the converted Sucat thermal plant and co-generation needs of industrial zones along its route;

- A high-pressure gas transmission pipeline from the Bataan peninsula to Metro Manila (BatMan 2), of 130 to 150 kilometres in length, that will supply gas to the Limay plant and possibly the Sucat plant; or alternatively, a 40 km undersea high pressure gas transmission pipeline from the Bataan peninsula to Metro Manila or Cavite province (BatCave) to serve the power plants and the cogeneration needs of industrial zones in Cavite province;

- A 35 km high-pressure gas transmission pipeline from Sucat to Pililia, Rizal province, to fuel the 650 MW Malaya thermal power plant that currently runs on fuel oil;

[20] Philippine Enegy Plan, 2003-2012. Department of Energy (DOE) 2003.

- A 40 km city gas pipeline network along Metro Manila's main road artery (EDSA and Taft Avenue) to serve large commercial users and refilling stations;
- LNG receiving terminals in the Bataan peninsula or Batangas province; and
- A network of refuelling stations for natural gas vehicles in Batangas and Metro Manila.

An LNG receiving facility is also envisaged in Bataan which will be anchored on the conversion of Limay oil thermal plant to natural gas. The plan is to build a 40 km undersea high-pressure gas transmission pipeline that will traverse Manila Bay which will transport LNG from the Bataan peninsula to Metro Manila or Cavite province. Alternatively, the Batangas LNG facility could service the needs of the Sucat or Malaya power plants. These plants could fill the need for additional gas-fired generation capacity in 2008.

NON-POWER

Significant use of gas is envisaged not only by electricity generators, but also by industry, commercial enterprises, and public transport. Industries clustered along the proposed pipeline routes are expected to tap gas from the network to provide process heat and conditioning requirements. Firms in some 20 industrial parks and economic zones can harness gas for their various needs. The government is studying the use of natural gas for lighting and air conditioning of large commercial establishments such as shopping malls, airports and hospitals. The government, through the DOE in cooperation with transport groups and industry players, has also earmarked the operation of 100 public utility transport buses running on natural gas by 2004.

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 PERTONAS NGV Sdn Bhd in Kuala Lumpur in May 2002 where six of the so-called Enviro 2000 utility vehicles were brought in from Malaysia.

The DOE is currently undertaking the establishment of CNG refilling stations network. The DOE, Shell Philippines Exploration B.V.(SPEX) and Pilipinas Shell Corp. (PSPC) has initially agreed to put up a CNG Fueling Station Pilot Project which is expected to be operational by mid-2004.

DEVELOPMENT OF THE DOWNSTREAM OIL INDUSTRY

Since the start of deregulation in 1998, the combined investments of the three oil majors and 74 new players have resulted in the establishment of new petroleum product facilities. As of December 2002, the total storage capacities are 4, 903.5 thousand barrels (MB) for Luzon, 879 MB for Visayas and 1,246MB in Mindanao.

The total investments put-in by the new players was already Php 14.7 billion. With the increase in investment of the new players, their market share also rose from a mere 4.3 percent in 1998 to 14.1 percent in 2002. It is still in the LPG sector where the market share of the new players have significantly increased to 32.2 percent in 2002. In the retail market, new players have put into operation 15 percent of the 3,746 gasoline stations constructed all over the economy.

Another strategy which the government implemented to encourage new players is the development of the Gasoline Station Training and Loan Program (GSTLP) through the support provided by the Philippine Amusement and Gaming Corporation (PAGCOR).

As part of the consumer welfare/empowerment programs, the partnership of the public-private sector was highlighted through the creation of the LPG and the Liquid Fuel Task Forces.

The Department, through the Oil Industry Management Bureau (OIMB), has also deliberated on the formulation of quality standards for unleaded gasoline (ULG) and coco-methyl ester (CME);

fuel quality requirements under the Clean Air Act (CAA) and the guidelines for retailing liquid petroleum products taking into consideration health, environmental and safety aspects.

Another challenging task of the Department was the updating of the Oil Contingency Plan (OCP) which was finalised in May 2002 as part of the Energy Contingency Plan. Since about 95 percent of the economy's requirement for crude oil is sourced from the Middle East, an Oil Contingency Plan was necessary to establish preparedness in case a war erupts in the said region. The OCP does not only address the supply issue disruption in the industry but it is a vital component to national security preparedness. The OCP will be operationalised by various agencies of the government, with the DOE as the lead agency.

PRICE OF PETROLEUM PRODUCTS

In pursuance to its mandate per Republic Act No. 8479 to ensure the reasonableness of domestic prices of petroleum products, the DOE continues to monitor daily the international prices such as Dubai, Brent and WTI for crude oil and the Mean of Platts Singapore (MOPS) spot prices for petroleum products. Based on available, data, the Philippines enjoys the lowest fuel prices among non-oil exporting countries in the region.

The DOE embarked on a tri-media campaign of informing the various publics, thereby empowering the consumer to make their choice. It provided a daily price monitor to print and broadcast media, government agencies and consumer and transport groups. Such information gave the public an indication of relevant trends in the international market and the possible impact on domestic petroleum products prices. To further aid the consumers, the Department continued to regularly monitor the petroleum price movements in the retail market. This paved the publication of the Power of Choice Ads, which features the prevailing domestic prices of LPG and liquid fuels of various stations of the different oil companies in Metro Manila.

RESTRUCTURING OF THE POWER INDUSTRY

Government continues to seek ways to lower the costs of electricity to consumers, one of which is through electricity industry reform. The Electric Industry Reform Act (EPIRA) of 2001, or R.A. 9136, which was enacted in June 2001, among others, will ensure the lowering of electricity rates and cut down government expenses and losses from the operation of its weakening electric power industry.

New entities were created. The Energy Regulatory Commission (ERC) was created to replace the Energy Regulatory Board (ERB). It is an independent quasi-judicial regulatory body in charge of promoting competition in the power sector, encouraging market development and ensuring customer's choice. It will continue to be the regulator of the transmission and distribution sector and ensure fair market practices in the deregulated environment. The Power Sector Assets and Liabilities Management (PSALM) Corporation, takes over the ownership of all the assets and liabilities of NPC. It shall manage the sale, disposal and privatisation of NPC and liquidate all its financial obligations. It shall also own the National Transmission Corporation (TRANSCO) where NPC's transmission and sub-transmission assets are transferred. The Philippine government plans to also privatise TRANSCO to make it more efficient.

The Philippine government has promulgated and will be implementing a Wholesale Electricity Spot Market (WESM), which according to the DOE is the first of its kind in Asia. Once in place, consumers will be able to choose the source and supplier of their electricity needs. WESM is seen to facilitate competition in the production and consumption of electricity, which will bring a downward pressure on electricity prices. Next steps include Creation of a Technical Working Group (TWG) for WESM composed of the government and industry participants; establishment of an Autonomous Group Market Operator (AGMO) to run the WESM, a petition to the Energy Regulatory Commission for approval of the WESM price determination methodology and market fees; and procurement of an interim Market Management System (MMS). The WESM is expected to be fully operational in 2003.

Since 2001, aside from mandating an automatic reduction of 30 centavos per kWh to electric customers (through RA 9136), President Arroyo has ordered the National Power Corporation (NPC) to further reduce its purchased power cost adjustment to its customers and fix it to 40 centavos per kWh to bring further relief to its customers. The President has initiated a 10-point plan to provide guidance in ensuring further reduction of electricity rates.

10 POINT PLAN TO LOWER ELECTRICITY RATES

Heeding the people's call for reduced electricity prices, President Arroyo has formulated ten possible ways of bringing down electricity rates which emphasis on reflecting the true cost of service in the rates, introducing price incentives to stimulate demand, optimising the utilisation of generation capacity to minimise costs, establishing a competitive wholesale generation market, accelerating open access to give end-users the power of choice, requiring efficient performance of distribution utilities, strengthening and consolidating the electric cooperatives, reducing independent power producers' (IPP) contract costs, exploring financial engineering to reduce stranded costs, and enhancing the Energy Regulatory Commission's capability to promote consumer welfare. All these, according to the DOE, together with the other provisions of EPIRA, will provide a lasting solution to the serious problem of high electricity tariffs.

IPP CONTRACTS REVIEW

Section 68 of RA 9136 ordered the review of the IPP contracts to help reduce the cost of electricity while respecting the validity of existing contracts and honouring government obligations. Only six out of the 35 contracts reviewed have been found free from legal and financial issues. Although the details of the renegotiations were not known to the public, the DOE has assured that no contract will be abrogated. As of 2002, the government, through PSALM, has successfully renegotiated its 18th contract with an IPP bringing to US$992 million the total savings generated by the government.

According to the DOE, a pending proposal from PSALM to the Senate would recover the stranded contract cost of NPC. By imposing a uniform or flat rate of 40 centavos per kWh over a period of 20 years, this will translate to about Php600 billion. The government also plans to dispose of NPC's prised and lucrative assets. PSALM estimates that with NPC's privatisation, the economy hopes to realise an annual savings of about US$500 million or Php25 billion in financing charges.

RURAL ELECTRIFICATION

Owing to the enhanced cooperation efforts among the DOE, its attached agencies and other entities (particularly the IPPs), 85 percent of villages now have access to electricity. A total of 1,513 villages from July 2001 to June 2002 were energised. Therefore, as of 2002, only 6,264 villages remain un-electrified and are targeted for full electrification by 2006.

According to the DOE, more than Php6 billion is needed by the O' Ilaw Programme to achieve its target. The DOE estimates that the program would need at least Php900,000 to Php1.5 million per village for on-grid areas and Php300,000 to Php1.3 million for off-grid areas. This however excludes the costs necessary for the expansion of distribution lines, its rehabilitation and upgrade, and the setting up of substations and other ancillary services.

Aside from seeking assistance (or grants) from financial institutions, the DOE has encouraged the participation of the private sector, business associations, civil society and other interested parties in the financing and direct implementation of electrification projects. The IPPs are sought to advance their contribution to the electrification fund created pursuant to Energy Regulations (ER) 1-94. Advancing payment to the fund would mean fast-tracking the electrification of targeted villages. Likewise, private individuals or other interest groups are encouraged to 'Adopt-a-Barangay', or adopt a village proximate to energy consuming/producing facilities. At least one major power company and a foundation have committed and worked together to energise about 1,000 villages in 2002.

The government has initiated the take over of the Php18 billion debt of the electric cooperatives (EC). An executive order, issued in August 2002, has outlined the restructuring program for the ECs, which would, among others, authorise the condonation of the ECs loans incurred as of 26 June 2001. According to National Electrification Administration (NEA), the plan is not to get rid of poor performing ECs, but rather, to help the ECs improve its performance and deliver better and efficient service.

RENEWABLES

The Philippines asserts to be the world's second largest producer of geothermal energy for power generation with a capacity of 1,931 MW, next to the USA. In the next ten years, the government plans to install additional 1,200 MW or 62 percent of its current geothermal capacity to maintain, or surpass the USA and become the world's largest geothermal producer. To achieve this, the government is banking on more private sector investments and the adoption of modern exploration and development technologies.

Sunpower Philippines Mfg. Ltd., a subsidiary of US-based semiconductor firm, Cypress International, will put up a Solar Wafer Fabrication Plant in the economy. The facility is first in Southeast Asia and envisioned to make the economy an export hub of photovoltaic (PV) cells due to the production of 25 MW high efficiency PV cells in its first year of operation and ramping up t 150 MW in the next ten years. On the other hand, a 1-MW grid connected PV power plant in Northern Mindanao is due for completion by CEPALCO in June 2004.

Several initiatives in biomass technology development and utilisation yielded positive results. Victoria Milling Corporation (VMC) is set to generate 50 MW through the use of bagasse as fuel while Talisay Bioenergy, Inc. is gearing for 30 MW cogeneration plant.

Independent research studies have revealed that the Philippines is theoretically host to a renewable energy resource base of 250,000 MW. According to the DOE, bulk of this resource could come from its vast ocean area, extending 1,000 square kilometres across its archipelago. Based on the study, the potential capacity for this resource is theoretically estimated to be 170,000 MW. The DOE has initially identified 12 ocean energy potential sites. Likewise, a study conducted by the US-NREL in 1999 has revealed 10,000 square kilometres of windy land areas believed to have excellent wind resource potential. DOE estimates that these areas could support a theoretical wind potential capacity of 70,000 MW.

Based on a ten-year Philippine Energy Plan (2003-2012), the government plans to put up additional 2,723 MW of hydro capacity. This addition will bring the economies' hydro capacity from its current level of 2,518 MW to 5,241 MW by 2012. Other renewable energy sources (i.e. wind, solar, biomass, and ocean), likewise, will contribute an additional 355 MW. Of this total, 255 MW will come from wind-based power and the remainder, from solar, biomass and ocean. A total of 8,728 MW of RE-based capacity will be expected to power up the Philippines electricity system by 2012.

PNOC-EDC is pioneering the construction of a 40 MW wind farm power project in the northern part of Luzon, which DOE avows as the largest wind farm in Southeast Asia. The first phase of the project, financed through the Japan Bank for International Cooperation (JBIC) for US$48 million, includes the 40 MW turnkey wind farm, a substation and a 42 kilometres - 230 kV transmission line. The government has collaborated with a private power company and the Dutch government to help finance and complete the project in 2004. Likewise, North Wind Power Development Corporation (NWPDC) is embarking on a 25 MW wind power plant project in Northern Luzon. DANIDA is financing 70 percent of the total project cost of about US$24 million while the 30 percent equity will be put up by NWPDC.

The DOE is set to energise 100 percent of the remaining off-grid barangays by 2006 through the use of renewable energy technologies and applications such as PV-Battery Charging Station, PV Solar Home Systems, hydro and hybrid PV-Wind, Wind-Diesel, and PV-Diesel.

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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 its northern and eastern regions very sparsely populated. During the 1990s the population declined from 148.39 million in 1990 to 144.75 million in 2001.

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. Although GDP declined from 7.3 percent in 2000 to 5 percent in 2001, Russia's economy is continuing it strong development and making the third year of positive economic growth. The industrial production grew 4.9 percent and investment in fixed capital was up 8.7 percent. GDP in 2001 was estimated to be US$ 952 billion (at 1995 purchasing power parity dollars) and the inflation remains under control of the government was 21.6 percent. The official unemployment rate is about 8.8 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 2001), 4.6 percent of the world's proven oil reserves (7.8 BCM in 2001) and 15.9 percent of the world's coal reserves (157 billion tonnes in 2001). 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 2001, the energy industry accounted for 13 percent of GDP and energy sector accounted for approximately 40 percent of the economy's export including oil and natural gas.

Table 31 Key data and economic profile (2001)

Key data		Energy reserves*	
Area (sq. km)	16,888,500	Oil (MCM) - Proven	7,727
Population (million)	144.75	Gas (BCM)	47,570
GDP Billion $ (1995 $ at PPP)	951.78	Coal (Mt) - Recoverable	157,010
GDP per capita (1995 US$ at PPP)	6,575		

Source: Energy Data and Modelling Center, IEEJ. * The BP Statistical Review, 2003.

ENERGY DEMAND AND SUPPLY

PRIMARY ENERGY SUPPLY

In 2001, Russia's total primary energy supply was 611.5 Mtoe. This total comprised 51.3 percent natural gas, 21.4 percent crude oil and petroleum products, 15.9 percent coal, 11.4 percent others including nuclear and hydro. Russia is a large net exporter of energy. In 2001, 37percent of energy production was exported, mainly to Eastern and Western Europe. Currently, Russia is developing new eastern energy export routes.

OIL

In 2001, Russia produced 348.1 Mtoe of crude oil and gas condensate, net exports of crude and petroleum products totalled 225.8 Mtoe, and the annual average refinery capacity was 276.4 Mt.

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.

NATURAL GAS

Natural gas production in 2001 totalled 325.3 Mtoe. Net exports accounted for 152.7 Mtoe or 31.3 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 2001, Russia produced 100.7 Mtoe of coal, declined 5.8 percent 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 of coal in national energy balance and power generation in particular.

Table 32 Energy consumption & supply for 2001

Primary Energy Supply (ktoe)		Final Energy Consumption (ktoe)		Power Generation (GWh)	
Indigenous Production	981,560	Industry Sector	154,979	Total	891,284
Net Imports & Other	-370,018	Transport Sector	73,478	Thermal	578,405
Total PES	611,542	Other Sectors	214,446	Hydro	175,850
Coal	100,672	Total FEC	442,904	Nuclear	136,935
Oil	135,665	Coal	49,865	Others	94
Gas	325,316	Oil	85,458		
Others	49,889	Gas	117,339		
		Electricity & Others	190,241		

Source: Energy Data and Modelling Center, IEEJ.

For full detail of the energy balance table see http://www.ieej.or.jp/apec/database/selecttable.html

ELECTRICITY

Russia produced 891.3 GWh of electricity in 2001. Of which 64.9 percent was produced from thermal fuels (gas, coal and fuel oil), 19.7 percent by hydro and 15.4 percent by nuclear.

Hydropower performs an important function to regulate peak loads in the unified power grid. The largest stations and the most prospective resources are located in southern Siberia; however, the capital costs of new hydro are prohibitively high. There are significant untapped hydro energy 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 2001 Russia operated 30 nuclear reactors with installed capacity of about 22.2 GW. They are mainly located in the European part of Russia.

FINAL ENERGY CONSUMPTION

In 2001, total final energy consumption in Russia was 442.9 Mtoe, a decline of about 15 percent compared with last year. By sector, industry had accounted for 35 percent share, transport for 16.6 percent and other sector for 48.4 percent. By fuel shares, coal accounted for 11.3 percent, petroleum products 19.3 percent, natural gas 26.5 percent and electricity & others 42.9 percent.

There are some clear signs of inefficient energy use in the national economy. Therefore, the final energy intensity in Russia 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 - 45 percent of total energy consumption. The most important energy use is for space heating, comprising about 40 percent of total final consumption due to the harsh cold climate.

POLICY OVERVIEW

MARKET LIBERALISATION

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

In October 2002 Prime Minister Mikhail Kasyanov pointed out that Russia might have deregulated electricity and gas markets within the next five years. So far, during the transition period, the government is keeping control over the tariff-setting policy for natural monopolies' services.

In March 2003, Russian President Vladimir Putin signed six bills into law to substantially reform the industry. By this law, tariff rates on the domestic market could be liberalised by July 1, 2005 and Unified Energy System should be liquidated in 2006. Electricity generation and distribution networks are expected to be privatised, while the economy's transmission grid will remain under the control of the Government.

The coal sector has been restructured since 1996 with support of the World Bank. Rosugol, the state coal monopoly has been restructured and privatised. In 2002, 77 percent of the total coal production came from independent producers.

STRATEGIC OIL RESERVE

The idea to create a strategic oil reserve has been debated in the federal parliament (Duma) in the early 1990s but then after the swift privatisation of state oil assets the interest has been lost. The debate over the reserve was revived in January 2002, when oil companies were suffering from an oversupply on the domestic market due to the government export limitations which had resulted from an agreement with OPEC.

At the US-Russia energy summit in Houston, 1-2 October 2002, the Energy Minister Igor Yusufov said that Russia needed a reserve of 50 Mt. Infrastructure construction and filling the reserve will cost an estimated $ 20 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.

Industry experts recommended that the government exploit the opportunity to buy cheap oil and then sell it later at a profit while supporting demand at the same time.

ENVIRONMENTAL POLICY

The economy is struggling to contend two major environmental problems: air pollution and nuclear waste. The carbon emission intensities in Russia are relatively high as the economy is dominated by fossil fuel utilisation. Russia has signed the Kyoto Protocol and we is now preparing for its ratification. The ratification will ensure Russia's entry into carbon trading with the quota trading estimated to reach at least 300-500 million tonnes annually for the period 2008-2012, considered as the "first commitment" period.

To provide legal framework in managing nuclear wastes, government has passed a legislation that allowed permanent storage of other countries' nuclear waste in Russia.

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, the regions where there is a shortage of energy. In particular, the Far East region permanently experiences power supply 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.

To improve the 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.

Unified Energy System of Russia (UES) plans to invest US$ 14 billion for the development of the hydroelectric sector in the Far East and Siberia. The plan will put more hydro generation in Far East after the inauguration of the Beureya Dam in July 2003.

The Sakhalin project 1 is being led by Exxon Neftegaz in cooperation with SODECO, ONGC, VIDESH, Sakhalinmorneftegaz and RN Astra. The project started drilling in May 2003 and expected the first oil production of 13 million tons in 2005. While the Sakhalin 2 is being developed by Shell, Mitsubishi and Mitsui to develop the first liquefied natural gas facility (LNG) with capacity of 10 million tons per year in the south of Sakhalin island. Russia had signed a contract to export around 30 percent of the plant output to three utility companies in Japan for 20 years , and is still marketing the remain throughput.

ENERGY COOPERATION

Russia has established energy cooperation agreements with several countries, particularly China, Japan, Korea and USA.

Notable recent energy cooperation with China are:

- In 2002, Russia and China have agreed to speed up the construction of an oil pipeline stretching from the Siberian region of Irkutsk to China's north-eastern oil centre of Daqing. The 2,400 km pipeline is planned 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 is a member of an international consortium that will lay a gas pipeline from west China towards Shanghai. The construction

of the 4,200 km line is expected to be completed 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 WITH USA

- In July 2002 Russia has made the first direct oil shipments to the US market. Government officials and oil industry representatives estimate the potential supply at as much as 1 Mbd, or 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.

ENERGY COOPERATION WITH JAPAN

- 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.
- Possible development of the Angarsk –Nakhoda pipeline to export oil to Japan.

NOTABLE ENERGY DEVELOPMENTS

NEW GAS JOINT VENTURE COMPANY

The Joint-venture consortium for production of natural gas in Russia’s Urengoi field has singed between Gazprom and Germany Wintershall in June 2003 to develop the Russia’s Urengoi having a recoverable reserve at 55 Tcf of gas and around 2.7 barrels of condensate. The first development phase is expected to start in 2004 and full production in 2008 with 291 Tcf of gas. The consortium plans to sell 75 percent of their natural gas production in domestic market and 25 percent of the rest production will be exported.

GAS PIPELINE DEVELOPMENT

The extending 746 miles of the North Trans- Gas pipeline from Baltic Sea port city of Vyborg in Russia through under the Baltic Sea to Germany, then cross the Netherlands and under the North Sea to United Kingdom was signed by Russian Government and United Kingdom in June 2003. The cost of the pipeline is expected at US$5.7 billion, and transport approximately 1.1 Tcf a year. The project will in operation with first capacity of 0.7 Tcf in 2007 and increase to 1.1 Tcf in later years.

The 750 miles blue stream natural gas pipeline connects gas system of Russia to Turkey with 246 miles under the Black Sea with an initial gas flow of 71 Bcf a year in December 2001 and will increase to 222 Bcf per year in 2009. But in March 2003 Turkey halted deliveries through this gas system. Invoking a clause in the contract allowing either party to stop deliveries for six months.

NEW OIL TERMINAL

The construction of an oil trans-shipment terminal on the island of Visotsky in the Leningrad region will be built by an agreement between LUKOIL and the US governmental agency OPIC (Overseas Private Investment Corporation). According to the agreement the US private investment fund HBK Fund will loan US$ 225 million to Visotsk-LUKOIL-II for a twelve-year period. OPIC and CSFB will act as guarantors for the loan. It is the first time LUKOIL is attracting such long-term loans without having to use export sales as security. OPIC, in its turn, is for the first time financing a project which is 100 percent Russian. The new oil terminal will allow LUKOIL to significantly raise the volume of oil it exports and also reduce the cost of its transportation. The terminal will be capable of transferring 11 million tonnes of oil a year and the first section of the terminal is expected to open at end of 2003 or early 2004. Up to now, about US$ 170 million has invested in the construction of the oil terminal by LUKOIL.

NEW OIL CONSORTIUM

The Oil Company Tyumen (TNK) with British Petroleum (BP) and Yukos with Sibneft have merged in February 2003 to become new oil consortiums: TNK-BP and YukosSibneft. YukosSibneft becomes the largest oil company in Russia and one of the largest in the world with oil proven reserves of 18.4 billion barrels and production capacity estimates about 110 billion tons per year. The YukosSibneft also controls seven refinery plants and 2,500 filling stations. While, TNK-BP holds oil reserves of 5.2 billion barrels and oil production capacity expected at around 60 billion tons, making it the third largest oil producer after Lukoil company in Russia. Before the merging, oil industry in Russia was dominated by five oil companies: Yukos, Lukoil, Surgutneftegaz, Tyumen Oil Company and Sibneft. The new oil combined company accounts for around 70 percent of the total oil production. Russia plans to produce about 410 Mt of oil in 2003 and expects to export 225 Mt of crude oil in 2003.

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SINGAPORE

INTRODUCTION

Singapore is a small island nation located between Malaysia and Indonesia. The total area of the island is 682.3 square kilometres, and the population in 2001 was 4.1 million. Despite its small size and population, Singapore is one of the more highly industrialised and urbanised economies in the Southeast Asian region.

In 2001, real gross domestic product (GDP) was US$ 86.1 billion and per capita GDP was US$ 20,841 (both in 1995 US$ at PPP). Because of its strategic location on the Straits of Malacca, Singapore serves as an important shipping centre and host to a large petroleum refining industry. Singapore however does not have its own energy resources and relies entirely on imports to meet its energy requirements.

Table 33 Key data and economic profile (2001)

Key data		Energy reserves	
Area (sq. km)*	682.3	Oil (MCM)	-
Population (million)	4.13	Gas (BCM)	-
GDP Billion US$ (1995 US$ at PPP)	86.09	Coal (Mt)	-
GDP per capita (1995 US$ at PPP)	20,841		

Source: Energy Data and Modelling Center, IEEJ. * Singapore Department of Statistics.

ENERGY DEMAND AND SUPPLY

PRIMARY ENERGY SUPPLY

Singapore is a net energy importer. Its domestic energy supply depends on imported oil and gas. In 2001 Singapore imported 42,465 ktoe of energy, mostly oil. More than half of the oil imports was re-exported as refinery products, while the other half was retained for domestic use. Oil accounted for 80 percent of the domestic supply, the remainder was gas. The four-fold increase of gas share in energy supply, from 2 percent in 2000 to 8 percent in 2001 was mainly due to gas imports through pipeline from Indonesia.

Singapore's electricity demand grew at an average of 6.4 percent per annum from 1996 to 2002 and is expected to grow from 3 to 5 percent per annum from 2003 through 2013. The amount of electricity consumed in 2001 was 33,089 GWh. The electricity was produced from 8,919 MW installed thermal generation capacity using heavy fuel oil and gas. By plant types, in 2003, Singapore installed generation capacity consists of 52.7 percent steam plant, 29.9 percent combined cycle plant, 10.8 percent cogeneration plant, 5.1 percent gas turbine and 1.5 percent incineration plant.

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 are in the form of oil fuel, mostly for transport and industry, while about a quarter is in the form of electricity.

Singapore's final energy consumption decreased to about 3 percent from 10,529 ktoe in 2000 to 10,186 ktoe in 2001, despite the increase in electricity generation. The slow down on energy consumption, which was shared by all sectors, was due to the negative growth (-2 percent) which Singapore experienced in 2001.

Table 34 Energy supply & consumption for 2001

Primary Energy Supply (ktoe)*		Final Energy Consumption (ktoe)*		Power Generation (GWh)	
Indigenous Production	-	Industry Sector	3,759	Total	33,089
Net Imports & Other	22,008	Transport Sector	4,317	Thermal	33,089
Total PES	22,008	Other Sectors	2,110	Hydro	-
Coal	-	Total FEC	10,186	Nuclear	-
Oil	17,556	Coal	-	Others	-
Gas	4,452	Oil	7,519		
Others	-	Gas	117		
		Electricity & Others	2,550		

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

PRICING

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

Since January 1992, Singapore had been using natural gas from Malaysia for its electricity generation as a first step towards energy supply diversification. Natural gas from West Natuna has been imported by SembCorp Gas Pte Ltd from January 2001 for a period of 22 years. In February 2001, Gas Supply Pte Ltd, a wholly-owned subsidiary of PowerGas Ltd, signed a gas sales agreement (GSA) with Pertamina for the import of 350 mmscfd of natural gas over 20 years from the Asamera gas field in Sumatra. The gas landed in Singapore since September 2003.

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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 22.4 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. The weak demand for consumer electronic products, which Chinese Taipei Economics heavy rely on, has lead to the recession in 2001. The economy experienced a negative growth (-2.2 percent) with GDP decreasing to about US$ 332.6 billion and a GDP per capita of US$ 14,844 in 2001 (in 1995 US$). However, in 2002, Chinese Taipei immediately recovered and gained momentum to attain a real GDP growth rate of 3.5 percent. The recovery will likely continue in 2003, at projected growth of 3.8 percent.

Chinese Taipei has very limited domestic energy resources and relies heavily 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 2001, the total electricity generation reached 30,136 MW.

Table 35 Key data and economic profile (2001)

Key data		Energy reserves**	
Area (sq. km)	36,000	Oil (MCM) - Proven	0.6
Population (million)	22.41	Gas (BCM)	76.5
GDP Billion US$ (1995 US$)*	332.59	Coal (Mt) - Recoverable	1.0
GDP per capita*	14,844		

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 84,566 ktoe in 2001, of which 46 percent was provided by oil, 35 percent by coal, 12 percent by nuclear power and 7 percent by natural gas. Some 87 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 2001, Chinese Taipei produced 188,519 GWh of electricity, of which 76 percent came from thermal power plants, 19 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 after the wholesale electricity market was opened to competition in 1994, independent power producers (IPPs) have expanded rapidly.

Table 36 Energy supply & consumption for 2001

Primary Energy Supply (ktoe)		Final Energy Consumption (ktoe)		Power Generation (GWh)	
Indigenous Production	10,751	Industry Sector	29,648	Total	188,519
Net Imports & Other	73,815	Transport Sector	12,370	Thermal	143,863
Total PES	84,566	Other Sectors	12,399	Hydro	9,169
Coal	29,358	Total FEC	54,417	Nuclear	35,486
Oil	39,128	Coal	8,820	Others	-
Gas	6,044	Oil	30,125		
Others	10,036	Gas	1,473		
		Electricity & Others	13,999		

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 7 percent in 2001 to 54,417 ktoe. The industrial sector utilised 54 percent of the total energy consumption, while the transportation sector and other sectors each used up 23 percent. Oil is the dominant fuel, accounting for 55 percent of energy consumption. Electricity accounted for 26 percent of energy use, coal 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 the 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 ultimate goal of the Chinese Taipei energy is to promote energy security supported by secure import of oil, gas and coal as well as the development of domestic energy resources, fossil fuel and renewable. For environmental reason Chinese Taipei plans to triple LNG consumption by 2010. To increase the efficiency of its energy sector the government announced that it would accelerate its privatisation.

To secure the domestic supply of oil, Chinese Taipei has required its oil refineries to maintain a stock at least for 60 days for securing domestic supply from any disruption.

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, with the promulgation of Petroleum Administration Act in 2001. The oil market liberalisation process accelerated in 2003 by allowing foreign firms to acquire stakes in CPC on equal basis with domestic investor.

NOTABLE ENERGY DEVELOPMENTS

OIL SUPPLY EMERGENCY RESPONSE

Due to the apparent impacts of the US-Iraq War on oil supply and oil prices, Chinese Taipei has established "Oil Emergency Response Committee" according to "Oil Emergency Response Plan".

Government officers, representatives from Chinese Petroleum Corporation and Formosa PetroChemical Company and two scholars composed the Committee. The Energy Commission completed the draft of "Oil Emergency Response Measures" which includes measures in response to four levels of oil stock shortage, that is, 10 percent, 20 percent, 30 percent and 40 percent.

These measures include prohibiting exports of oil products, restricting office hours of gas stations, opening limited gas stations and allocating oil products. Currently, the onset for applying these measures is based on the degree of oil stock shortage without considering international oil prices.

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, Formosa PetroChemical Company, Lee Chang Yung Chemical Industry Corporation, Ming-Xing Enterprises, Esso Petroleum Taiwan and Caltima Corporation have joined the Chinese Petroleum Corporation. In oil refining, Ho Tung Chemical Corporation that has obtained a permit to build a refinery in Taichung will soon join the Chinese Petroleum Corporation and Formosa PetroChemical Company.

Esso Petroleum Taiwan Inc. and Caltima Corp. got their oil importing permits for gasoline and diesel fuel on 27 February and 13 August 2002, respectively. Esso Petroleum Taiwan Inc. started its importing business on 26 March 2002.

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.

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.

NEW AND RENEWABLE ENERGY

THE FIRST REFUSED-DERIVED FUEL PROCESSING DEMONSTRATION PLANT

In accordance with the aim of implementing the "Refuse Energy Utilisation Technology Development Project", the Energy Commission of Chinese Taipei has facilitated the signing of a contract between the Hualian County Government and the Energy and Resources Laboratories of the Industrial Technology Research Institute on 2 August 2002 on the construction the first Refuse-derived Fuel Processing Demonstration Plant in Chinese Taipei.

The designed processing capacity of the plant is 1KG of municipal waste per hour. The plant is scheduled to be established and enter into commercial operation by the end of 2003.

WIND POWER

Taipower has decided Taichung Harbour Wind Power Generation Project. The total investment estimated will exceed 3 billion New Taiwan Dollars. The project will be implemented in two stages. There will be 36 wind power units by 2007, with capacity of 1.8MW each.

Chinese Taipei has completed a Wind Energy Potential Map, to be provided for business interested in wind power facilities. Currently, there are eight wind power generator sets in Chinese Taipei. Four sets are in Penghu County, with a capacity of 600 KW each, and the other four sets, with a capacity of 660 KW each, are located at the Mailiao Power Station of Formosa PetroChemical Co. Many other companies, including foreign ones, are currently proposing new projects to the Energy Commission.

BIOMASS

A combined biomass gasifier-based power plant and recycling center is under construction in Yun-Lin Country of Chinese Taipei in order to fully utilise agriculture wastes such as rice straws, husks and rice barns. The electricity generated is approximately 33.4 MWh per annum upon completion.

RENEWABLE ENERGY DEVELOPMENT BILL

In order to effectively promote renewable energy and respond to the requirements of the private sector for institutionalised incentive measures, Chinese Taipei has made a "renewable Energy Development Bill" after referring to the successful experience of Germany in legislating the Renewable Energy Law and consulting with a variety of experts.

The bill has gone through the deliberation of the Executive Yuan and has been delivered to the Legislative Yuan. The legislation of renewable energy-related laws is also one of key items in "Challenging 2008: The Six-Year National Development Plan".

The bill aims at attracting investments in renewable energy by providing incentives to potential investors, therefore accelerating the adoption of renewable energy.

Chinese Taipei intends to create a sustainable environment that harmonises environment protection, energy security and economic development by enforcing the bill. It is also hoped that electricity from renewable resources will be able to make up over 10 percent of the total electricity generation capacity.

NON-NUCLEAR HOMELAND

On 13 February 2001, Chinese Taipei's legislative and executive departments signed an agreement, publicly proclaiming that the future planning of the economy's overall energy development should, on the premise of maintaining a constant and sufficient supply of energy, take into account such relevant factors as national economy, social development, world trends, and the spirit of international trends, so as to achieve the economy's ultimate goal of building a "Non-Nuclear Homeland".

The ideal of "Non-Nuclear Homeland" was legitimised through the adoption of "The Fundamental Environmental Protection Act" in 2002, which illustrated that "The government should gradually achieve the goal of non-nuclear homeland".

The contents of non-nuclear homeland include the following tasks: ending the threats of nuclear weapons, reviewing the various uses of nuclear power for peaceful purposes, developing renewable energy, caring for the humanity and equality of all people, and refusing nuclear pollution.

To achieve the goal, Chinese Taipei established "The Non-nuclear Homeland Council", which comprises eight task groups: energy structure adjustment, clean energy promotion, nuclear power plant phasing-out, nuclear waste management, Non-nuclear Homeland legislation, the 4th nuclear power plant monitoring, non-nuclear promotion, and Non-nuclear Homeland education.

The Non-nuclear Homeland Council is also responsible for driving the legislation of the "Non-nuclear Homeland Law" which serves as the base law for formulating future non-nuclear homeland policies. In this Law, issues such as adjustment of energy mix, decommission of nuclear power plants, targets for cleaner energy development, participation in decision-making on major nuclear related issues, supervision of nuclear safety, and the integration of the non-nuclear concept into energy education policies will all be pragmatically and adequately addressed within a proper legal structure. Currently, the Law has been approved by the executive authority and sent to the legislative department for consideration.

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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 and the east. It has an area of 513,115 square kilometres and a population of about 61.2 million at the end of 2001.

Over the past two decades, engendered by 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 developed its energy sector to the extent that import dependency has been declining throughout the period. In 1997, an economic recession in Thailand caused by the Asian financial crisis, resulted in negative economic growth and a decline in energy demand for the first time in 30 years. Two of the effects of the crisis were the depreciation of the currency and higher inflation and up until the first half of 1999, the resulting recession weakened domestic purchasing power; notably in the prices of imported energy such as oil. However, by the second half of 1999, economic countermeasures taken by the government began to take effect and a gradual recovery, particularly in the industrial export sector, has since taken hold. Currency levels stabilised and the inflation rate declined. However, in 2001, GDP was US$ 364.2 billion (at US$ 1995 at PPP), a slightly increase of 1.8 percent over 2000.

Thailand is highly dependent on energy imports, particularly oil. In 2001, net energy imports accounted for 57 percent of energy supply in the economy; down significantly from 96 percent in 1980.

Table 37 Key data and economic profile (2001)

Key data		Energy reserves*	
Area (sq. km)	513,115	Oil (MCM)	52
Population (million)	61.18	Condensate (MCM)	41
GDP Billion US$ (1995 US$ at PPP)	364.23	Gas (BCM)	378
GDP per capita (1995 US$ at PPP)	5,953	Coal (Mt) - Recoverable	1,354

Source: Energy Data and Modelling Centre, IEEJ. * Proved reserves, Department of Mineral Fuels, Ministry of Energy.

ENERGY DEMAND AND SUPPLY

PRIMARY ENERGY SUPPLY

In 2001, the primary energy supply was 67,035 ktoe. Oil comprised 51.4 percent of primary supply, gas 34.1 percent, coal 13.3 percent and others 1.2 percent. Energy imports accounted for 56.8` percent of primary energy supply in 2001, slightly higher than 55 percent in 2000.The supply of oil was slightly down compared to 2000 and the 6 percent increase in primary energy supply was almost entirely due to a 16.7 percent increase in gas supply.

In 2001, Thailand imported 92 percent of its oil requirements. A high level of import dependence is expected to continue in the foreseeable future. The 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 2001, Thailand's total proven reserves of crude oil were around 52 MCM. Onshore reserves are located in the Sirikit field (17.5 MCM) while offshore reserves (33.6 MCM) are mainly in the Benchamas, Jarmjuree, and Maliwan fields. For condensate, total proven reserves are 41 MCM. All deposits are located offshore with major pools in the Bongkot, Pailin, JDA and Erawan areas.

Due to the lingering effects of the financial crisis and high oil prices, domestic petroleum product consumption in 2001 was lower than might otherwise have been the case meaning that domestic refineries were not required to operate at full capacity. Capacity utilisation in 2001 was around 88 percent. To mitigate losses, Thai refineries were exported some of their output. Exports of petroleum products were 6,427 ktoe in 2001, 13.4 percent increase from 2000, and imports were 434 ktoe, 64 percent decline compared to the previous year. 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 21 percent of demand. Gas production was around 13.4 percent higher in 2001 compared with 2000. 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 1,354 Mt, most of which is located in the Mae Moh basin. Around a third of coal requirements are imported.

Total electricity generation in 2001 was 102,420 GWh, 6.7 percent more than in 2000. Almost all domestic production was thermal generation (94 percent). The remaining 6 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 3 percent of requirements.

Table 38 Energy supply & consumption for 2001

Primary Energy Supply (ktoe)		Final Energy Consumption (ktoe)		Power Generation (GWh)	
Indigenous Production	28,926	Industry Sector	13,762	Total	102,420
Net Imports & Other	38,109	Transport Sector	18,805	Thermal	96,115
Total PES	67,035	Other Sectors	11,501	Hydro	6,303
Coal	8,898	Total FEC	44,069	Nuclear	-
Oil	34,479	Coal	4,418	Others	2
Gas	22,890	Oil	30,142		
Others	769	Gas	1,572		
		Electricity & Others	7,937		

Source: Energy Data and Modelling Centre, IEEJ.

For full detail of the energy balance table see http://www.ieej.or.jp/apec/database/selecttable.html

FINAL ENERGY CONSUMPTION

Thailand's total final energy consumption for 2001 was 44,069 ktoe, an increase of 6 percent over the previous year. Petroleum products account for the highest proportion of secondary demand (68 percent), followed by electricity (18 percent), lignite coal (10 percent) and gas (4 percent). Demand for natural gas and electricity increased by 13 and 5 percent respectively from 2000. On the other hand, petroleum demand grew by 4 percent.

The transportation sector was the largest energy consuming sector and accounted for 43 percent of total final energy consumption. This was a lower share than the 45 percent in 2000 and at 18,805 ktoe was only 0.1 percent less than consumption in 2000. The industry sector consumed

13,762 ktoe in 2001, an increase of 7 percent from the previous year. Energy consumption in the residential and commercial sectors increased by 16 percent over 2000.

Electricity demand is estimated to have increased by 5 percent between 2000 and 2001. Although hydro generation was near 5 percent higher in 2001 than in 2000, Thailand still depended on fossil fuels for around 94 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)[21] 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 share market float of 32 percent of its capital in December 2001.

[21] National Energy Policy Office (NEPO) is the former name of Energy Policy and Planning Office (EPPO). NEPO renamed to EPPO after the restructuring of Thai government agencies in 2002.

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 semi-deregulated from November 2001, with full de-regulation planned for 2003. LPG remains the dominant fuel for cooking.

Competition in the gas supply industry is now allowed for the direct purchasing and selling of natural gas of new gas supplies. Third party access to transmission and distribution pipelines is allowed where excess capacity exists and in the case of new pipelines. Currently, PTT is the only operator in the gas pipeline business. An independent gas regulatory agency is planned for establishment in 2006.

ELECTRICITY

Thailand is attempting to improve the efficiency of the electricity market by a process of de-regulation and promoting competition. A process begun in 2000, complete deregulation for electricity industries is planned for 2004. According to the master plan, during 2003-2004, three state own 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 their own supplier(s).

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

With a view to decreasing the growth of energy consumption in the 2002-2011 periods, 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. Thailand targeted to reduce its energy consumption by 6.6 percent or 4,823 ktoe in 2006 and 8.5 percent or 9,306 ktoe by 2011.

RENEWABLE ENERGY

Thailand extensively promotes the development of renewable energy resources. Currently the economy is constructing a 42.5 MW solar power plant in the northern province at Mae Hong Son. The plant, which is expected to be in operation in 2004 will have the ability to produce 1,750 kWh and will support the growing demand in the region. Thai government plans to increase the electricity generation capacity to 30 MW by 2006. The Thai citizens are fully supportive of the government's plan to expand the share of solar power in the energy mix. Around 20,000 Naresuan University communities utilised solar power on minibuses, public phones and ovens.

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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 2001. The US is located in North America between Canada and Mexico. It has a population of 285 million people (2001), 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. A brief recession meant slower growth of 0.3 percent in 2001 and 2.4 percent in 2002, with unemployment increasing from 4.0 percent at the end of 2000 to 6.1 percent in mid-2003. The slowdown in the US economy, the world's largest in size and net imports, acted as a drag on growth in other economies. A recovery by late 2002 was expected to yield growth of about 3 percent in 2003 and 4 percent in 2004.

The United States is the largest producer, consumer, and importer of energy in the world. It is also wealthy in energy resources. At the start of 2003, there were 3,562 Mcm of proven oil reserves and 5,182 Bcm of natural gas reserves. In 1997, there were some 275 billion tonnes of recoverable coal reserves, up 10 percent from two years earlier. Electricity generating capacity in 2001 totalled 813 GW, of which about 65 percent was owned by utilities and 35 percent by non-utility generators. But due to a large and wealthy population and extensive industrial base, the economy consumed 5.5 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 (2001)

Key data		Energy Reserves**	
Area (square km)*	9,372,610	Oil (MCM) - Proven	3,562
Population (million)	285.32	Gas (BCM)	5,182
GDP Billion US$ (1995 US$ at PPP)	9,200	Coal (Bt) – Recoverable***	275.1
GDP per capita (1995 US$ at PPP)	32,243		

Source: Energy Data and Modelling Center, IEEJ. * US Energy Information Administration.

** Oil and gas reserves as of 1 January 2003. *** Coal reserves as of January 1, 1997.

ENERGY DEMAND AND SUPPLY

PRIMARY ENERGY SUPPLY

In 2001, net primary energy supply in the United States was about 2,145 Mtoe. By fuel type, 39 percent of supply came from crude oil and petroleum products, 25 percent from coal, 24 percent from natural gas and 12 percent from nuclear, hydro, geothermal and other fuels. The United States imported about 24 percent of its energy requirements in 2001.

During 2001, the United States used approximately 845 Mtoe of petroleum. Petroleum product supply grew 1.5 percent per annum during the 1990s, but domestic crude oil production levels declined by 2.2 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 44 percent of crude oil demand was met by imports in 1990, the import share had climbed to 60 percent by 2002. 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. Four-fifths of the economy's oil reserves are located in Texas, Alaska, Louisiana and California, which are the four largest states in terms of current oil production.

The United States contains about 3.3 percent of the world's natural gas reserves. Primary natural gas supply totalled 516 Mtoe in 2001, exceeding domestic production by 13 percent. Most of the production shortfall was met by imports from Canada through an extensive network of pipelines. Gas use by industry and power generators has grown because gas is a clean fuel that favours environ-mental approvals. It growth was assisted by a period of falling wellhead gas prices following their deregulation in the 1980s and by an expanding pipeline network that made gas more widely available.

Strong demand and other factors have led to higher natural gas prices in recent years. During the winter of 2000-2001, average wellhead prices more than doubled from those of the previous winter. While spot prices at the Henry Hub reference had fallen by August 2001 to half the winter's peak, they were still well above those two years earlier. In March 2003, city gate gas prices and delivered gas prices to electricity producers and industry were roughly double those a year before. Average wellhead gas prices per thousand cubic feet doubled from $1.96 in 1998 to $4.12 in 2001, fell by a fourth to $2.96 in 2002, surged by two-thirds to nearly $4.90 in 2003, and were projected to subside by a fifth to around $4 in 2004 – similar to prices in 2001 but double those in 1998. Market mechanisms are working to meet gas needs reliably, albeit at prices on a jagged upward trend.

Table 40 Energy supply & consumption for 2001

Primary Energy Supply (ktoe)		Final Energy Consumption (ktoe)		Power Generation (GWh)	
Indigenous Production	1,638,138	Industry Sector	504,043	Total	3,757,844
Net Imports & Other	506,764	Transport Sector	638,431	Thermal	2,690,563
Total PES	2,144,902	Other Sectors	449,765	Hydro	208,143
Coal	532,152	Total FEC	1,592,238	Nuclear	768,826
Oil	844,511	Coal	67,415	Others	90,312
Gas	516,430	Oil	843,856		
Others	251,809	Gas	398,950		
		Electricity & Others	282,018		

Source: Energy Data and Modelling Center, IEEJ (see http://www.ieej.or.jp/apec/database/selecttable.html)
Note: Source figures are derived from official US Energy Information Administration data, but differ due to adjustments, combinations and reallocations by IEEJ for various fuels and end-use sectors which arise from definitional differences.

Coal use in the United States totalled 532 Mtoe in 2001. US coal reserves are concentrated in Appalachia and key western states. Appalachian coal, which accounted for 36 percent of production in 2002, 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 2003, production declined in Appalachia but grew in the West.

The United States is the fifth largest coal exporter in the world behind Australia, South Africa, Indonesia and China. Since 1995, US coal exports have fallen sharply due to lower world coal prices, increased competition among coal-producing economies, and substitution of natural gas for coal in power production. In 2001, US coal exports fell to their lowest level since 1978, as a strong dollar made coal from elsewhere cheaper and high spot prices for domestic coal made it attractive for producers to sell at home, and they fell still further in 2002 to a level not seen since 1961. By the first half of 2003, US coal exports to Asia (mainly Japan and Korea) had virtually evaporated, and total US coal exports were down 1.6 percent from 2002, with a 7 percent decline in exports to

Europe offset by increases of 15 percent to North America, 17 percent to South America and 74 percent to Africa.

The United States produced 3.7 million GWh of electricity in 2001 with 72 percent coming from thermal plants, 20 percent from nuclear power, 6 percent from hydropower, and 2 percent from other sources. Of the thermal generation, roughly three-quarters was fuelled by coal and one-quarter by natural gas, with small amounts produced from oil and other fuels. Average electricity prices per kWh fell every year between 1993 and 1999 but rose to 6.9 cents in 2000 and 7.3 cents in 2001, largely because of higher gas prices, before declining to 7.2 cents in 2002 and 2003.

The United States generates more nuclear power than any other economy 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 over 90 percent in 2002. 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 November 2003, the NRC had approved license extensions for 19 nuclear units and had applications for another 16 extensions under review, while 23 further units were expected to seek extensions by the end of 2006.

FINAL ENERGY CONSUMPTION

In 2001, end use energy consumption in the United States totalled 1,592 Mtoe. Broken down by sector, transport consumed 40 percent, industry accounted for 32 percent, and residential and commercial buildings used 28 percent. By fuel, petroleum accounted for 53 percent of consumption, natural gas for 25 percent, coal for 4 percent, and electricity and other fuels for 18 percent.

POLICY OVERVIEW

Energy policy in the United States is very supportive of market mechanisms. The Department of Energy (DOE) is responsible for implementing energy policies and programmes initiated by the Congress, monitoring the state of energy markets, maintaining energy security, and supporting research and development of new energy technologies. The Federal Energy Regulatory Commission (FERC) and various 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 1975. With a stock of nearly 635 million barrels in late 2003, the SPR is the largest emergency oil stockpile in the world. The government intends to fill the SPR to its 700 million barrel capacity by 2005 through a “royalty-in-kind” exchange program whereby oil produced from federal leases in the Gulf of Mexico is exchanged for oil going into the SPR. In the late 1990s, the SPR was upgraded to ensure its full and safe operation until at least 2025.

The SPR represents a total investment of more than US$20 billion with an annual requirement in the range of US$158 million for maintenance and operation. The average price paid for oil in the reserve is about US$27 per barrel. Crude oil is stored mainly in four underground salt caverns on the Gulf Coast in Texas and Louisiana, with a distribution system in place for the oil’s use. DOE manages the SPR facilities and periodically conducts test sales and releases. The current SPR inventory could replace roughly 53 days of imports, down from a peak of 118 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. Upon order of the President, oil can be delivered to the US market within 13 days at a maximum rate of 4.3 million barrels per day.

TECHNOLOGIES AND POLICIES TO LIMIT ENVIRONMENTAL IMPACTS

The United States has made substantial progress in reducing environmental impacts of energy use. 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.

To extend this progress, objectives for further reducing emissions of sulphur dioxide, nitrogen oxides, and mercury were announced by the government in 2002. 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 Clean Coal Initiative, begun in 2002, pledges US$2 billion in federal cost sharing over a ten-year period to advance such technologies, with at least half the funding for each project coming from private sources. Since earlier efforts have already made a great deal of progress in reducing traditional air pollutants such as particulates, SOx, and NOx, current efforts are increasingly focused on reducing greenhouse gas emissions. A FutureGen demonstration plant is being designed to separate carbon and hydrogen streams from coal so that all the carbon can be sequestered without entering the atmosphere. If the costs are not too high, carbon separation and sequestration could point the way to a hydrogen economy in which continued use of coal is environmentally sustainable.

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.

The Congress has approved development of Yucca Mountain, in 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. Independent experts at the Nuclear Regulatory Commission (NRC) are reviewing the scientific study of Yucca Mountain and will later consider the site for a license.

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, currently around 1.8 cents per kWh, 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 and briefly lapsed for new facilities after 1999 before being extended through 2001 and later through 2003. A further extension through 2006 is included in the Energy Policy Act that was being considered by the Congress in late 2003. Uncertainty about the credit has contributed to an uneven pattern of with power capacity additions, which plummeted from some 700 MW in 1999 to just around 50 MW in 2000, rebounded sharply to a record of some 1,700 MW in 2001, crashed to less than 500 MW in 2002, and soared again by preliminary estimates to roughly 1,600 MW in 2003. Total installed wind capacity at the end of 2003 was thus expected to exceed 6 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 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.

About fifteen states have implemented renewable energy goals or portfolio standards, including such large states as California and Texas. 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 (mpg) for cars since 1985 and 20.7 mpg 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 24.4 mpg by 2001. However, a statutory prohibition on examination of fuel efficiency standards by the Department of Transportation (DOT) was lifted in December 2001. In April 2003, DOT issued a final rule raising fuel economy standards for light trucks by a total of 7 percent to 21.0 mpg in 2005, 21.6 mpg in 2006 and 22.2 mpg in 2007.

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, with major US automakers, in the Partnership for the Next Generation of Vehicles and then the Freedom CAR initiative, to 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. The Energy Policy Act of 2003 (see below) provides tax credits for efficient and alternative-fuel vehicles

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-fourth of all electricity 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; very little new capacity is being provided by traditional vertically integrated utilities.

The competitive power market came about as a result of initiatives by the Federal Energy Regulatory Commission (FERC). FERC orders 888 and 889, issued in 1996, required investor-owned utilities to open up their transmission systems to competing power providers on a non-discriminatory basis. Order 2000, issued in 1999, 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. FERC's authority to issue these orders was upheld by the Supreme Court in 2001.

In July 2002, FERC issued a Standard Market Design proposal to govern the structure and operation of wholesale US power markets. FERC's idea is that all utilities that own, operate or control interstate transmission should conform to this standard design. 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. But the Energy Policy Act of 2003, if passed, would prohibit a final Standard Market Design rule before the end of 2006.

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 would help FERC monitor the market for potential anticompetitive actions by market participants. Each RTO would 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 would 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 would 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 would 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 would 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 would 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 markets would 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 during any day or hour. This would ensure that electricity trade is not pursued at the expense of reliability. Market-clearing prices would 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 would also be limited by allowing demand reduction measures to be bid into the spot market.

Investment: Several aspects of the Standard Market Design would promote required investment in new transmission capacity, generating plants and conservation. The market for CRRs would allow suppliers to hedge transmission cost uncertainty and would assign values to congestion that could signal the need for investment to relieve transmission bottlenecks. Locational marginal pricing at each point on the grid would potentially signal where investment in generation and transmission is needed to improve grid operations. Companies that invest in new transmission would be allowed to retain rights to the added power-transfer capacity. A generation adequacy requirement would compel companies serving retail customers to arrange sufficient supplies and demand reductions to meet peak demand plus a 12 percent reserve margin. Infrastructure needs would 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 could 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.

NOTABLE ENERGY DEVELOPMENTS

RECORD BLACKOUTS HIT NORTHEAST IN SUMMER 2003

On 14 August 2003, the United States and Canada experienced the largest blackout in history, affecting some 50 million people and nearly 62 GW of generating capacity. In the United States alone, the blackout affected customers along some 34,000 miles (54,000 km) of transmission lines and put some 290 generating units out of service. In some parts of the United States, power was not restored for two days. The blackout involved thousands of distinct but related events.

The U.S. – Canada Task Force on the Power System Outage issued an interim report in November 2003 on the causes of the blackout. It assesses the conditions on the transmission grid that contributed to the blackout, outlines the physical causes of the outage, and discusses events and conditions that allowed the blackout to spread. It places substantial blame on one utility company and one independent system operator, noting specific ways in which they violated operating procedures established by the North American Electric Reliability Council. The report will provide the basis for recommendations, at a later date, on how to reduce the likelihood of future blackouts and make the electric power infrastructure more reliable.

ENERGY POLICY ACT OF 2003

The Energy Policy Act of 2003 was submitted for approval by the Congress late in the year, as a compromise between versions passed earlier by the House and Senate. The legislation was given increased political urgency by the summer blackouts, so certain controversial provisions were deleted to expedite its passage. These include provisions that would have allowed drilling for oil in Alaska's Arctic National Wildlife Refuge and would have required improved vehicle fuel efficiency. Since the legislation passed the House but not the Senate, a revised version should be considered in early 2004.

The act would make some significant changes in electricity regulation. It repeals the Public Utility Holding Company Act (PUHCA) of 1935, which had restricted the entry of some competitive generators into the power market. It substitutes a simplified PUHCA that gives state and federal regulatory authorities access to books and accounts of holding companies and their associates, affiliates and subsidiaries. This should ensure continued oversight of potential market abuses such as cross-subsidisation of competitive functions (generation and supply) by regulated functions (transmission and distribution). In addition, the act confirms FERC's authority to set competitive conditions on electric utility mergers, to approve or disapprove market-based rates for service, and to require that merchant transmission lines offer service to all electricity suppliers on fair terms.

To help ensure reliable electricity supply in a power industry where competing suppliers have economic incentives to cut costs as much as possible, the act would require that all users, owners and operators of transmission or generating facilities on the power grid comply with reliability standards. This should mean that participation in the North American Electric Reliability Council (NERC), which had been voluntary, would be mandatory. In addition, the act calls for the federal government to coordinate state actions that affect regional energy infrastructure and to "be attentive to electric power transmission issues … that can be addressed through policies that facilitate investment in, the enhancement of, and the efficiency of electric power transmission systems." However, there are no provisions for overriding state decisions regarding transmission line siting permits.

An Electric Energy Market Competition Task Force would be established to assess the progress of competition in wholesale and retail electric power markets. It would be tasked to examine:

- The best means of protecting competition;
- Unfair, discriminatory or deceptive practices;
- Activities, including mergers and acquisitions, that suppress competition;
- Possible cross-subsidisation between regulated and non-regulated activities; and
- The role of state public utility commissions in regulating competition.

Several provisions of the act relate to renewable energy. Production tax credits for wind power and closed-loop biomass would be extended for three years through the end of 2006. Production tax credits would be expanded to include solar and geothermal energy, as well as energy from municipal and agricultural waste. Intermittent wind and solar power generators would receive nondiscriminatory access to transmission service and would be offered transmission service on a non-firm (as available) basis. But proposed economy-wide renewable energy portfolio standards, requiring that a rising portion of electricity be generated from renewable sources, were not included in the conference bill.

There are also important provisions related to nuclear energy. The Price-Anderson Act, which indemnifies nuclear power plant licensees against potential damage from nuclear accidents, would be extended through 2012, with liability limits on licensees increased to $10 billion. A study is to be done on the feasibility of building commercial nuclear plants on sites owned by DOE. A project is to be launched to investigate technology for cogeneration of nuclear power and hydrogen fuel.

The act would establish an office of climate change technology within DOE to focus on breakthrough technologies for mitigating greenhouse gas emissions or for removing and sequestering greenhouse gases from emission streams. The office would collect and analyse data to assess whether engineered and terrestrial sequestration will be economically feasible and whether geological or ocean sequestration is stable. Meanwhile, an appropriations bill provided funds for fiscal year 2004 to initiate the FutureGen project to build and demonstrate a zero-emission facility which produces electricity and hydrogen from coal while sequestering greenhouse emissions.

The act would provide a wide array of tax incentives for energy production, conservation, and advanced technologies. Many of the incentives aim to encourage domestic oil and gas production, with specific provisions for marginal wells and offshore facilities. Tax credits would be provided for vehicles powered by fuel cells, vehicles with advanced lean burn (low pollution) technology, and hybrid vehicles with both electric and heat engines. The amount of vehicle tax credit would vary with the extent to which vehicles exceed 2002 fuel economy standards. Credit amounts would also depend on vehicle weight in the case fuel cell vehicles, lifetime fuel savings in the case of lean-burn vehicles, and the potential electric share of vehicle power input in the case of hybrid vehicles. The act calls for a major increase in the use of ethanol (mainly from corn crops) as a vehicle fuel additive.

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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 79.5 million (2001). Its GDP in 2001 was about US$ 156.3 billion, and its GDP per capita was US$ 1,965 (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 In 2001, Vietnam's GDP growth slightly slowed down to 6.8 percent.

Energy is a key component in Vietnam's economy, supporting recent industrialisation, and contributing to exports earnings. Viet Nam is well endowed with fossil energy resources such as oil, gas and coal, as well as renewable like hydro, biomass and solar energy. As of 2001, 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 capacity. Natural gas and crude oil are found mainly in the southern region, while coal reserves (mostly anthracite) are located in the northern region.

Table 41 Key data and economic profile (2001)

Key data		Energy reserves*	
Area (sq. km)	331,111	Oil (MCM) - Proven	420
Population (million)	79.53	Gas (BCM)	617
GDP Billion US$ (1995 US$ at PPP)	156.27	Coal (Mt) -Recoverable	3,325
GDP per capita (1995 US$ at PPP)	1,965		

Source: Energy Data and Modelling Center, IEEJ.

* Institute of Energy, *Viet Nam 2000*.

ENERGY DEMAND AND SUPPLY

PRIMARY ENERGY SUPPLY

In 2001, Viet Nam's total primary energy supply was 16,437 ktoe, more than 10 percent in 1991. Oil was the most important fuel, making up 50.8 percent of primary supply. Coal made up 30.1 percent of primary supply, gas 9.5 percent and others 9.5 percent. About three-fifths of indigenous energy production was used domestically while two-fifths, mostly crude oil and coal, was exported.

Viet Nam produced 17,244 ktoe of oil in 2001, more than 4.3 times with 1991. Most oil exploration and development in Viet Nam occurs offshore in the Cuu Long and Nam Con Son Basin. Though 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 accounted for 49 percent of production in 2001.

Gas production in Viet Nam only began in 1995 and is still very low. As new gas fields and a new pipeline system came into service, gas production increased by 24 percent from 1,440 ktoe in 2000 to 1,563 ktoe in 2001. 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; any surplus gas is flared.

Viet Nam's coal production has increased by 6.0 percent in 2001 to 7,200 ktoe. About 40.3 percent of coal production 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 15.1 percent in 2001 to 30,608 GWh. Most of the increase came from hydro power plants, which generated 25.1 percent more electricity than the year before and accounted for 59.5 percent of output. Thermal power plants increased only 3.0 percent in 2001 and it provided the remaining 40.5 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 about 100 new power plants including hydropower, coal-fired and gas-fired plants as well as a nuclear power plant.

Table 42 Energy supply & consumption for 2001

Primary Energy Supply (ktoe)		Final Energy Consumption (ktoe)		Power Generation (GWh)	
Indigenous Production	27,759	Industry Sector	4,916	Total	30,608
Net Imports & Other	-11,322	Transport Sector	4,163	Thermal	12,398
Total PES	16,437	Other Sectors	3,937	Hydro	18,210
Coal	4,955	Total FEC	13,017	Nuclear	-
Oil	8,353	Coal	3,674	Others	-
Gas	1,563	Oil	7,104		
Others	1,566	Gas	15		
		Electricity & Others	2,223		

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 13,017 ktoe in 2001. In 2001 alone, final consumption grew about 1.65 percent for the economy as a whole and 10.3 percent for the industrial sector, while transport sector decreased 2.7 percent. Of the total consumed in 2001, industry accounted for a 37.8 percent share, transport for 32.0 percent, and other sectors for 30.2 percent. The industry share will rise as Vietnam builds up heavy industries like petroleum, metals, chemicals, fertiliser, power plants and building materials. By fuel shares, oil satisfied 54.6 percent of end-use demand in 2001, coal 28.2 percent, electricity 17.1 percent, and gas is lowest level at 0.1 percent. But electricity grew fastest, up by 15 percent in 2001, followed by coal with 2 percent growth, while oil decreased 2.2 percent. 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 products. By developing regional indigenous resources and expanding regional co-operation, 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 feasibility study of the economy's second US$2.49 billion oil refinery and petrochemical complex is in progress and expects to get government approval in 2003. The project is prepared by PetroVietNam in cooperation with Mitsubishi Corporation and JGC Corporation of Japan, and located in Nghi Son district in Thanh Hoa province, 125 kilometres South of Hanoi. The refinery plant 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 million metric tonnes of crude oil a year, while the petrochemical complex will produce polypropylene and polyester fibers, LPG, kerosene, diesel, FO, bitumen and other chemicals and plastics. The complex will include a harbour for loading products and a 100 MW power plant. The refinery will be a joint venture company with one third of the total investment should be financed by Petrovietnam and the rest will be from foreigner partners according the feasibility study.

There was a change in the proposed investment plan for the first US$1.3 billion refinery plant in Dung Quat central Quang Ngai province. It was once a joint venture between PetroVietNam and Russia's Zarubeznheft group, but in 2003, Russia withdrew from the project as it failed to get an agreement for the acquisition of a modern technology for the plant. This has delayed the project for another year, pushing back the project completion to 2006, instead of 2005. The refinery is capable of refining 130,000 barrels a day or 6.5 million tonnes of crude oil per year. The plant will also produce 2,084 million tons of automotive diesel, 1.95 million tons of unleaded gasoline, 1.33 million tons of diesel oil, and more than 100,000 tons of propylene. 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 through loans from domestic and foreign financial institutions.

In parallel with the construction of the Dung Quat Oil Refinery, PetroVietNam has carried out several other projects in preparation for Dung Quat's production activities scheduled for 2005. Three major petroleum storage systems will be located in Dinh Vu (Hai Phong city), Nha Be (HCM 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 boost its strategic long-term development. PetroVietNam's financial organisation will 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 its investment overseas, and is pursuing production-sharing contracts with Indonesian, Malaysian, Mongolian and Algerian partners. It has recently secured two contracts to exploit petroleum overseas.

COAL

The Viet Nam National Coal Corporation (VINACOAL), established by the Prime Minister in 1994 and operating under a Decree № 13/CP and № 27/CP of Government in 1996, 1997 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 Viet Nam Dong (VND) 7.5 trillion to build coal - fired plants with a total capacity of 2,500 MW, 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 and from 15 million to 17 million tonnes each year from 2001 through 2005, up to 24 million tonnes in 2010. VINACOAL is expected to spend a huge investment for ensuring safety and effective management, as well as making use of modern technology, equipment in mining, screening and processing lines, and transportation to reduce environmental pollution. In 2002, to boost coal production, VINACOAL begun a contract system of production expenses, production selling, and profits for Coal subsidiary Companies.

ELECTRICITY

Electricity of Viet Nam (EVN), which was established in 1995, reports directly to the Ministry of Industry (MOI). EVN formulates the electricity policy and strategy for the sector. Up to now, EVN controls seven distribution companies, four transmission companies, seventeen 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 State Price Committee (SPC), on the other hand, is responsible for evaluating electricity prices and submitting them to the Government for approval.

In 2003, the average electricity price reached about VND 840 per KWh (US$ cent 5.49), an increase of 13 percent compared with its last year average. The ceiling for electricity tariffs in rural areas had also increased to VND 700 per KWh from VND670 per KWh in 1997. Electricity price will be regulated by the Government to match the long-run marginal cost of US$ 7 cent per KWh in 2005 to finance new power plants and pay debts.

The electricity growth rate is projected by EVN to be at 15 percent, 13 percent and 8 percent in 2005, 2010 and 2020, respectively. 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.

NEW MANAGEMENT MODEL OF EVN

The new model of electricity sector is being made by EVN to restructure its various businesses into a parent-subsidiary model with purpose of improving financial management and operational efficiency in the sector. According to the model several power plants and some provincial electricity distributors will become limited liability companies or joint-stock companies. The power plants located in Vinh Son, Song Hinh, Ba Ria-Vung Tau, Ninh Binh, Uong Bi, Thu Duc and Can Tho, which will be changed into single-member limited liability companies. The joint-stock power companies will be responsible for selling electricity directly to consumers. Other organisations involved in selling electricity in communes will be allowed to buy shares in the joint-stock companies.

A PUMPED HYDROPOWER STORAGE STATIONS PROGRAM

Viet Nam has a plan to develop a pump-storage hydropower station in some locations from the North to South of the economy to make full use of power output during off-peak hours. Since December 2002, EVN with the financial and technical assistance of Japan International Cooperation Agency (JICA) has carried out a feasibility study of the project, and has identified 6 of 26 locations for these power stations. Five locations are in the Northern mountainous regions of Son La province and one in the central area of Ninh Thuan province. Production cost of the pumped-storage hydropower station is projected to be at US$680-US$760 per KW.

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 million kilowatts of power 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

OIL AND GAS SECTOR

MANAGEMENT CHANGE

In 23 May 2003, the Government of Viet Nam has approved, through its Decision No 55/2003/ND-CP the transfer of the management of the Vietnam Oil and Gas Corporation (PetroVietnam) to the Ministry of Industry (MOI), instead of by the Government.

PETROLEUM PRICE CHANGES

Viet Nam has reduced the import taxes on some petroleum products in response to the recent volatility in world oil prices. The import taxes on automobile fuel and naphtha have been reduced to 10 percent from 20 percent. However, import taxes on other types of oil products remained unchanged. The import tax on aircraft lubricant oils is set at 5 percent, with jet fuel at 15 percent and solvent oils at 10 percent. The import taxes on condensate, kerosene and gasoline products remain at zero percent. This is the first time in 2003 the economy has adjusted import taxes to change domestic prices to reflect international oil price volatility. The new prices have taken in effect from Jan 24, 2003.

RUSSIA'S ZARUBEZNEFT WITHDRAW THE REFINERY PLANT IN VIETNAM.

Russia has agreed to withdraw from a US$1.3 billion joint venture to build Viet Nam's first oil refinery, amid differences over acquisition of technology for the plant. The two sides decided to change the form of co-operation under which the Vietnamese side would be the sole investor while Russia is only a contractor of some component parts. PetroVietnam and Russian partner Zarubezneft established the Vietross Joint Venture in 1999 to build the Dung Quat refinery in central Viet Nam, with an annual capacity of 6.5 million metric tonnes of crude oil. The two sides, holding equal stakes, had been unable to reach agreement on the acquisition of modern technology and equipment for the plant. PetroVietnam has already re-paid about US$230 million for Russia's group Zarubezneft. The money was contributed by Zarubezneft to the oil refinery project under a contract it had signed with PetroVietnam.

That volume would spend part of the repaid sum investing in other oil and gas projects in Viet Nam, particularly oil development projects in Bach Ho (White Tiger) and Thanh Long (Blue Dragon) oil fields off Viet Nam's coast.

PETROL FUELS- A83 AND A92 WILL BE PRODUCED.

The Condensate Processing Factory is expected to launch the petrol A83 and A92 in 2003, according to the Ministry of Trade. The Ministry expects the local production of petrol will ease the pressures caused by price fluctuations in the world markets. The (US$12 million) factory is located in the Southern province of Ba Ria-Vung Tau, and is expected to produce 270,000 tonnes of petrol and 26,000 tonnes of diesel oil from the condensate provided by the Bach Ho and Nam Con Son oil fields.

THE FIRST BOND ISSUE

The five-year bonds of VND 300 billion (US$19.35) has been sold by PetroVietnam on the domestic market in September, 2003 to finance for energy projects including the Dung Quat oil refinery plant and the Ca Mau gas complex that are under construction with total capital of US$2.4 million. It is the first corporate bond in the energy sector. Its interest for the first year would be 8.7 percent, declining to 8.16 percent in the next four years A decision on PetroVietnam's international bond issue is expected soon, given its new controlling body and increasing funding demand for energy projects.

Morgan Stanley has been the adviser for PetroVietnam's international bond issue, expected to be worth $300 - $500 million.

POWER SECTOR

REVISED ELECTRICITY MASTER PLAN

The Government has approved the revised Electricity Plan V with its growth rate of 15 percent annually (13 percent per year in the old plan was) early this year to meet the power demand for the economy to 2010. With the revised Plan, electricity demand is forecasted to be 48.5-53 billion KWh and 88-93 billion KWh in 2005 and 2010, respectively. To meet this target, EVN has to construct 10 new power plants with total capacity of 3,023 MW in 2005 and build new and expand 52 plants with total capacity of 10,197 MW during 2006-2010. Of the 52 plants, 42 are hydro power plants with combined capacities of 4,827 MW, while 4 and 6 are gas and coal fired power plants, each with combined capacities of 2,670 and 2,700 MW respectively. This will result to an average of 8 new power plants annually and a huge total investment of about US$ 15.1 billion. EVN could cover only 30 percent of the total costs, the remainder of which the Government expects to be financed from the private sector and foreign organisations.

NEW POWER PLANTS

Electricity of Viet Nam Corporation (EVN) is going to break ground for the construction of six more power projects in 2003 such as the 170 MW A Vuong and 75 MW Quang Tri hydropower plants in August, the 600 MW O Mon oil power plant in October, the 110 MW Pleikrong hydropower plant in November, and the 280 MW Buon Kuop hydropower and 600 MW Hai Phong coal-fired power plant in December.

EVN also started the expansion of the Uong Bi Thermal power Plant in Quang Ninh province with total capital investment of US$305 million, increasing its generation capacity to 400 MW from the current 100 MW. The expansion work will be completed within three years. At present, Vietnam has four coal-fired power plants with a total generation capacity of 1,245 MW, all these coal –fired power plants are located in the Northern part of the economy. The Government is planning to raise its coal-fired power supply to 3,200 MW by 2010.

THE SECOND OPTICAL FIBRE SYSTEM

EVN is building the second 1,500 km optical fibre system alongside the second 500 KV transmission line to manage the economy's power grid and to assist commercial telecommunications services such as domestic long distance and international telephone services as well as Internet access. The second 500 KV transmission line is stared from Phu Lam in suburban of Ho Chi Minh City in the South links to Pleiku province in the Central Highlands to Thuong Tin in Ha Tay province in the North, which is closeto Hanoi. By early 2004, the grid will be installed connecting Northern provinces as Yen Bai, Lao Cai and Tuyen Quang as well as Southern provinces as Can Tho, Soc Trang, Bac Lieu, Rach Ra and Ca Mau. The construction is expected to be completed in 2006. Between 2005 and 2006, several remote mountain regions in the North and South of the economy will have access to the National power network.

THE FIRST POWER JOINT –STOCK COMPANY

The Ry Ninh hydro power plant II constructed by Song Da corporation in Chu Pak, Gia Lai province has become the first Hydropower joint-stock Company in the Energy sector in Viet Nam in 30 November 2002. This is the first hydro power plant built through a BOT form that has been equities. The legal capital is around VND 28,5 billion with coupon value of VND 100,000 each. The plants have 3 units of 2,700 KWh each. The plant has generated around 30,600 KWh to EVN with selling price of US$ 4.1 cent per KWh in 2002.

COAL SECTOR

REVISED NATIONAL COAL STRATEGY.

The Government has approved the revised Master Plan of Coal Development (MPCD) during 2003-2010 and estimation to 2020. MPCD therefore has established Viet Nam's coal reserves to be 2.5 billion tons, less than the originally placed 3.8 billion tons. Coal production is projected to reach 16-17 million tons in 2005, 23-24 million tons in 2010 and 29-30 million tons in 2020. Total investment for the period 2003-2010 is expected to reach about VND 14,166 billion, of which VND 12,933 billion spend for remaining, expanding and building new mines.

Vinacoal will focus its efforts on the investigation and exploration of coal below -300m in Quang Ninh field as well as make up a step-by-step coal exploration in Red Delta Rever to meet the target of the energy development strategy. Enhance new coal technology, specially, in coal underground mines including mechanisation support of roadways to reduce loss level, increase productivity and safety.

In September 2003, VINACOAL has produced more than 11.5 million tons of anthracite and has exported 4 million tons of coal, an increase of 20 percent compared with last year.

INTERNATIONAL COOPERATION

Vietnamese Government has recently assigned Song Da Corp., one of Viet Nam's leading construction Companies, to develop a US$350-million hydropower generation project in Laos in the Build-Operate-Transfer (BOT). Construction work will be undertaken by State Utility Electricity of Vietnam, Civil Engineering Construction, Corporations 5 and 8 (Cienco 5 and Cienco 8). The construction will start in the second quarter of 2004 and put in operation in 2008. Viet Nam will buy some electricity from the hydro power plant.

The 220 KV cable line is being built by EVN to sell electricity to Cambodia. The US$10 million cable line with the total length of 100KM, capacity of 80MW and 200MW will start in Thot Not district, An Giang province and ends at Phnom Penh. To date, the EVN has had 3 cable lines to sell electricity for local areas at the border of Cambodia and Viet Nam.

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