ASIA PACIFIC ENERGY RESEARCH CENTRE

NUCLEAR POWER GENERATION IN THE APEC REGION

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FOREWORD

Energy demand is growing at accelerated rates and has the possibility of multiplying by a factor of 2 or more by the middle of this century. To cope, world economies will have to make better use of all available energy sources. Nuclear power has been an important component of the electricity systems in the APEC region since the 1950s, and today it generates 16 percent of all the electricity in the region. The electricity generated by nuclear power in APEC is roughly similar to that generated by natural gas plants or hydropower, yet there is debate concerning its viability due to concerns about its cost, safety, waste disposal and proliferation.

To properly design the energy systems for the future, in-depth and impartial assessments have to be made of all the available options. APERC has set out to make this study to give policy makers a better understanding of nuclear power's present standing and recent developments, as well as to give an assessment of what role nuclear power can play in the future of APEC.

This report is published by APERC as an independent study and does not necessarily reflect the views or policies of the APEC Energy Working Group or individual member economies. APERC recognises and respects the position of some APEC member economies that do not consider nuclear power an option for their energy systems.

We hope this report contributes to the ongoing dialogue about the future of nuclear power.

Masaharu Fujitomi
President
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GLOSSARY AND ABBREVIATIONS

ABARE	Australian Bureau of Agricultural and Resource Economics.
Actinides	Elements with atomic number of 89 (actinium) or more. Heavy elements present in high level waste produced by neutron capture of uranium in nuclear reactors. These have less radioactivity than fission products, but have the longest half-lives in high level waste.
AECL	Atomic Energy of Canada Limited.
APEC	Asia-Pacific Economic Cooperation.
APERC	Asia Pacific Energy Research Centre.
ATR	Advanced thermal reactor. Advanced reactor of the thermal, or low energy type.
BWR	Boiling water reactor.
BNFL	British Nuclear Fuels plc.
CANDU	Canadian Deuterium Uranium. Registered trade name for the Canadian-designed power reactor developed by Atomic Energy of Canada Limited and using natural uranium as fuel and deuterium oxide (heavy water) as moderator.
Capacity factor	The ratio of the actual electricity generated in the time period considered, to the energy that could have been generated at continuous full-power operation during the same period.
CCGT	Combined cycle gas turbine.
CEO	Chief Executive Officer.
CNNC	China National Nuclear Corporation.
CNSC	Canadian Nuclear Safety Commission.
Criticality	Said of the state of a nuclear reactor in which it achieves a self-sustaining nuclear chain reaction.
DUPIC	Direct Use of spent PWR fuel In CANDU (reactors). A combined nuclear fuel cycle being investigated by AECL.
EAR	Estimated additional resources.
EDF	Electricité de France.
EIA	Energy Information Administration, USDOE.
EPRI	Electric Power Research Institute. California, United States.
Fast reactors	Reactors in which the nuclear fission reactions take place in the high or fast energy ranges. Breeder reactors are a type of fast reactor.
FBR	Fast breeder reactor. A reactor type that operates in the high (or fast) energy range and that is designed to produce more fissile (fuel) material than is consumed.
FEC	Final Energy Consumption.
Fission products	Atomic fragments resulting from the fission of uranium in nuclear reactors. They are radioactive isotopes of elements lighter than uranium and contribute most of the short and medium term high level radioactivity in spent fuel.
FOAKE	First-of-a-kind-engineering costs.
Fuel cycle	Refers to the activities at every stage of the lifecycle of the nuclear fuel used in reactors. Activities generally include: uranium mining or recovery from other natural forms, uranium ore processing, uranium refining, heavy water production, uranium conversion and re-conversion (into appropriate chemical forms for enrichment, and back to original form afterwards),

	uranium enrichment, manufacture of fuel structural components, fuel fabrication, fuel burn-up inside a reactor, spent fuel reprocessing, and spent fuel and high level waste storage or disposal.
Gcal	Gigacalories, or 1 billion calories (10^9 calories).
GDP	Gross Domestic Product.
GHG	Greenhouse gases.
GIF	Generation IV International Forum. International organisation collaborating on the development of 6 innovative reactor and fuel cycle system designs for implementation about the year 2030.
GW	Gigawatt (one billion watts or one million kW).
GWh	Gigawatt-hour (one billion watt-hours or one million kWh).
HEU	Highly enriched uranium. Used in research reactors, reactors for naval propulsion and in the manufacture of weapons.
HLW	High level radioactive waste.
HTGR	High temperature gas-cooled reactor.
IAEA	International Atomic Energy Agency of the United Nations.
IEA	International Energy Agency of the OECD.
IEEJ	Institute of Energy Economics, Japan.
ILW	Intermediate level radioactive waste.
INPRO	International Project on Innovative Nuclear Reactors and Fuel Cycles. IAEA coordinated international research effort for the design of innovative nuclear systems.
IPP	Independent power producer.
ITER	International Thermonuclear Experimental Reactor. A collaboration project between Canada, the European Union, Japan and Russia for the development of the nuclear fusion energy concept.
JFEO	Japan Federation of Economic Organizations, or Nippon Keidanren.
JNFL	Japan Nuclear Fuel Ltd.
KAERI	Korea Atomic Energy Research Institute.
KEPCO	Korea Electric Power Corporation.
KHNP	Korea Hydro and Nuclear Power Company.
KSNP	Korea Standard Nuclear Power Plant.
kW	kilowatt (one thousand watts).
kWh	kilowatt-hour (one thousand watt-hours).
LCOE	Levelised cost of electricity.
LLW	Low level radioactive waste.
LMFR or LMFBR	Liquid metal cooled fast breeder reactor. Fast breeder type reactor using liquid sodium as coolant.
LNG	Liquefied natural gas.
LILW	Low and intermediate level radioactive waste.
LWR	Light water cooled and moderated reactor.
METI	Ministry of Economy, Trade and Industry, Japan.
MOCIE	Ministry of Commerce, Industry and Energy, Korea.
MOX	Mixed oxide fuels, nuclear fuels manufactured from a mix of uranium and plutonium oxides.
Mtoe	Million tonnes of oil equivalent.
MW	Megawatts (1,000 kilowatts or 1 million watts).
MWe	Megawatts of electric power output.

MWth	Megawatts of thermal, or heat power output.
NEA	Nuclear Energy Agency of the OECD.
NEI	Nuclear Energy Institute.
NPP	Nuclear power plant.
NRC	United States Nuclear Regulatory Commission .
NSSS	Nuclear steam supply system. The steam-producing section of a nuclear power plant comprised of the nuclear reactor itself, reactor containment vessel, pressurisers, steam generators, primary cooling circuit and circulating water pumps. The system provides steam to the power-producing turbine and generator group section.
NWMO	Nuclear Waste Management Organisation of Canada.
OECD	Organisation for Economic Co-operation and Development.
OPEC	Organisation of Petroleum Exporting Countries.
OPG	Ontario Power Generation.
PES	Primary Energy Supply.
PHWR	Pressurised Heavy Water Reactor.
Pluthermal	Term used in Japan to describe a nuclear fuel cycle that includes reprocessing and the use of recovered plutonium in conventional light water reactors of the low energy or thermal energy range type (as opposed to breeder reactors which operate in the high energy or fast energy range).
PPA	Power purchase agreement.
PPP	Purchasing power parity.
Pu	Plutonium.
PWR	Pressurised water reactor.
RAR	Reasonably assured resources.
RBMK	Water-cooled, graphite-moderated channel-type nuclear reactor, a Russian designed nuclear reactor.
R&D	Research and development activities.
RE or NRE	Renewable energies or new renewable energies.
Rosatom	Russian Federal Atomic Energy Agency.
Rosenergoatom	Russian state heat and electricity generation company
SWU	Separative work units. Unit of work used in enrichment processes for the separation of different isotopes.
TEPCO	Tokyo Electric Power Company.
Th	Thorium.
Thermal reactors	Reactors in which the nuclear fission reactions take place in the thermal or low energy ranges, as opposed to fast reactors that operate in comparatively higher energy ranges. Thermal reactors include light water reactors (BWR, PWR), heavy water reactors (CANDU), and others.
toe	Tonnes of oil equivalent.
Transuranics	Actinides with atomic number above 92 (uranium).
TWh	Terawatt-hours (1 billion kilowatt-hours or 1 million Megawatt-hours).
U	Uranium.
USEC	United States Enrichment Corporation.
USDOE	United States Department of Energy.
VVER	Water-cooled, water-moderated vessel-type pressurised power reactor, a Russian designed pressurised water reactor.

WNA	World Nuclear Association.

EXECUTIVE SUMMARY

There is a renewed interest in nuclear power worldwide. The number of nuclear power plants in Asia has been increasing in recent years. In North America and Europe, their safety record and the improvement in their generation costs have placed nuclear plants in a new light.

Energy consumption around the world and particularly in APEC continues to grow at an accelerated pace, with the possibility of doubling or tripling worldwide by the first half of this century. But there is also uncertainty about whether enough energy sources will be available to satisfy this expanded growth while at the same time reducing the emission of pollutants into the atmosphere. The role nuclear power can play in APEC in this scenario can be better assessed by analysing its current status and the forces driving the technology in the region, and by looking at the factors that will influence the development of nuclear power in the future.

The following are some important facts about the status of nuclear power in the APEC region: [1]

- APEC is a most influential region in the world in terms of nuclear energy. This is so because its members include the United States, which is the economy with the largest number of reactors in the world (with 104), and they also include Asian economies that account for most of the growth in nuclear power taking place worldwide.
- APEC is home to 240 of the 441 operating reactors in the world, totalling 205 GW, or 56 percent of the world's installed nuclear capacity. In 2003 nuclear reactors in APEC generated 1,415 TWh of electrical energy accounting for 16 percent of the total electricity generated in the region.
- Out of 35 reactors under construction in the world, 16 are in APEC for an additional installed capacity of 17 GW. Russia and Korea have 5 reactors under construction, while Japan, China and Chinese Taipei have 2 units each.
- There are reasonably firm plans for 34 more reactors in APEC for the future. The largest growth is expected in Korea, followed by China, Japan and Russia.

DRIVERS OF NUCLEAR POLICY IN APEC

The most important drivers of nuclear power in APEC are scarcity or uneven distribution of local energy resources, high expected electricity demand growth and the need to reduce greenhouse gas emissions.

- Economies in APEC with the highest share of nuclear power generation in their electricity systems are economies with high dependency on imported fuels. The most notable cases are: Korea, with an energy import dependency of 84 percent and a nuclear generation share of 40 percent; Japan with an energy import dependency of 80 percent and a nuclear generation share of around 30 percent; Chinese Taipei with an import energy dependency of 89 percent and a nuclear share of 21 percent; and United States, with an energy import dependency of 27 percent and a nuclear share of 20 percent.
- APEC's characteristic fast growing electricity demand will have to be satisfied with a diversified pool of energy sources. Economies in the region with some of the most aggressive nuclear expansion programmes are economies that have expectations of fast electricity demand growth in the future: China with an expected average electricity demand growth rate in the next 20 year period of 5.6 percent, plans between 32 and 40 GW of nuclear capacity by 2020. Korea with an expected electricity demand growth rate of 4.7 percent average for the next 20 years, plans a total of 28 operational units by 2015. Russia,

[1] As of April, 2004.

with an expected electricity demand growth rate of 3.8 percent, plans 50 GW of nuclear capacity by 2020 and 60 GW by 2030. Vietnam, the economy in APEC with the highest expected average electricity demand growth rate for the next 20 years, is evaluating plans for the construction of its first two nuclear plants to be operational by 2019, and a decision of whether or not to go ahead with the project is expected soon.

- All APEC economies with nuclear power programmes cite sustainable development as one of the major reasons behind it. Many APEC economies are committed to reducing greenhouse gas (GHG) emissions and in a few cases are even bound by international obligations to do so. Such are the cases of Canada, Japan, Russia, and New Zealand, all of whom are required under the Kyoto Protocol to reduce GHG emissions and are hard pressed for cleaner electricity generation sources. The first three, with some of the lowest CO_2 emission targets under Kyoto in APEC, together with United States, with its own programme to fight global warming, have active nuclear power programmes and are counting on them to aid in meeting their CO_2 emission goals.

ECONOMIC COMPETITIVENESS

For nuclear power to become once again a viable option for electricity generation, it should strive to be economically competitive without relying on factors external to the nuclear industry, such as increases in the prices of alternative fuels, and carbon taxing or trading schemes. Having said that, the economic competitiveness of nuclear power rests mainly on its ability to reduce investment costs. The following describe advances in the reduction of investment costs for new reactor units.

- Several vendors have announced prices for advanced reactor models that are lower than those of previous models. General Electric, Westinghouse and Atomic Energy of Canada Limited estimate to have costs for their advanced reactor models in the range of US$ 1,100 to US$ 1,600/kW. Such costs are comparable to the expected cost of an advanced coal plant in 2005 of US$ 1,170/kW.
- First-of-a-kind engineering effects however, will put cost premiums on the first few plants of any given new model. According to a study by the University of Chicago commissioned by the United States Department of Energy (USDOE), it is until the fifth unit of a new nuclear reactor model is constructed that the costs of producing electricity can be competitive against fossil fuelled plants, reaching by then costs of between US$ 34 and 39 per MWh.
- The costs of electricity production of the first 5 units of a new model can be brought down to competitive levels of around US$26 – 37 per MWh by combining a production tax credit of US$18 per MWh extending for 8 years, and a 20 percent investment tax credit, assuming that construction schedules can be kept below 5 years.
- Another option to share the risk and bear the costs of the first units built is the formation of consortia among reactor vendors, financial institutions and utilities that would commit to the construction of a minimum number of plants. The cost premium of the first few units would be averaged over a guaranteed number of plants and the risks would be equally distributed among all participants, with no further assistance in the form of government tax credits required from governments.

URANIUM RESOURCES

Enough uranium resources recoverable with today's technology exist to cover nuclear generation needs for the next 50 years or more. The higher the expansion of nuclear energy in that period, the more resources with less geological assurance and higher extraction cost would have to be used.

- According to the International Atomic Energy Agency (IAEA), at least twice as much undiscovered resources costing less than US$ 130/kg exist to fulfil the demand in the year

2050 even with an expansion that would allow nuclear energy to provide one-fourth of total electricity generation by the year 2100.

RADIOACTIVE WASTE MANAGEMENT

Enough experience exists in radioactive waste technology to safely manage every step of its handling and type of process required, except for the final disposal of high level radioactive waste (HLW).

- About 40 disposal facilities exist worldwide for the isolation of low and intermediate level radioactive waste (LILW) that have collectively amassed an experience of more than 35 years.
- Deep geological disposal is the type of repository most suited for the final disposal of high level radioactive waste, and the related technology is considered today sufficiently mature for its implementation. One such repository has been in operation in New Mexico since 1999 for the final disposal of long-lived transuranic wastes generated by the United States' nuclear military programme.
- Most commercial spent nuclear fuel in the world is currently undergoing a required cooling-off and decaying interim storage period, and therefore there is no urgent need for their final disposal. Nevertheless, plans are at an advanced state for the implementation of deep geologic repositories in several parts of the world, the most advanced being the Yucca Mountain project in Nevada in the United States which is scheduled to start operations by 2012.

ALTERNATIVE NUCLEAR POWER FUTURES IN APEC

- A nuclear generation share of 11 percent of the total power generation fuel mix can be had in the entire APEC region by the year 2050 in the Moderate Nuclear Development Scenario, which reflects moderate nuclear expansion programmes in all APEC economies with nuclear power programmes and includes 3 new nuclear economies. Gains possible from this expansion are:
    - Annual savings of 9 percent in fossil fuel consumption for power generation relative to the Low Nuclear Development Scenario. This is equal to 282 million toe of coal per year and 272 million toe of natural gas per year by the year 2050.
    - Avoided emissions accumulated over the 50-year period would equal 33 billion tonnes of CO_2, relative to the Low scenario. The cost of these avoided emissions at a carbon value of US$20/ton CO_2 is equal to US$ 660 billion.
- In the High Nuclear Development Scenario, that reflects the most optimistic nuclear expansion plans of APEC economies and incorporates 6 new nuclear economies, nuclear generation share in APEC can reach 19 percent by the year 2050. The gains in this case are:
    - The annual displacement of 18 percent of the fossil fuels used for power generation relative to the Low Nuclear Development Scenario, or equal to 540 million toe of coal per year and 528 million toe of natural gas per year by the year 2050.
    - Avoided emissions accumulated over the 50-year period would be equivalent to 63 billion tonnes of CO_2 compared to the Low scenario. These emissions would translate to a monetary figure of US$ 1,260 billion at a cost of US$20/ton CO_2 in the 50-year period.

AREAS FOR COLLABORATION IN APEC

There are areas for possible collaboration in APEC that could bring about benefits in cost, safety and security to all those involved.

- Some of the topics for collaboration could include: reactor technology development, centralisation of fuel cycle services, development of nuclear licensing procedures and regulation, and communication and social acceptance.
- In the realm of waste management, especially beneficial areas for collaboration could be the construction and operation of regional deep geological high level waste repositories, although at present there are a number of legal and political difficulties to implement them. Other more achievable proposals can be high level waste technology research, low and intermediate level waste processing and preparation methods, waste standards and licensing, capacity building, and the joint construction and operation of underground research laboratories.

CONCLUSION

Nuclear energy deserves to be reconsidered by economies planning their future energy systems. In view of the world's rapidly increasing energy demand and the reduced number of environmentally sound and dependable options to meet such demand, nuclear power stands as a viable option.

There is an overstatement of nuclear energy's drawbacks; especially over issues such as safety, waste, and economics. And there is also an understatement of nuclear energy's benefits. Many important concerns presently existing in APEC can be addressed by nuclear power. A comprehensive balance of benefits versus drawbacks might result in nuclear power being beneficial to a number of APEC economies. And a comparison of nuclear power against competing power generating alternatives could also render it attractive in some cases in the APEC region. But for nuclear power to have a prominent position in the electricity generation scene, advances have to be made on the most controversial issues. This will entail major responsibilities from participating economies and their governments to ensure continued safe operation of nuclear facilities, political decisions to develop and implement national waste management strategies, and international action to adopt more effective nuclear proliferation controls.

INTRODUCTION

BACKGROUND

There is a renewed interest in nuclear energy worldwide. The number of nuclear power plants in Asia has been increasing in recent years. In North America and Europe, their safety record and improvements in generation costs have placed nuclear plants in a new light.

The centre of nuclear activity has moved from North America and Western Europe to South and East Asia. Out of the last 40 nuclear plants connected to energy grids since 1995 around the world, 28 have been built in China, Japan, Korea, Russia, India and Pakistan. There are 133 nuclear plants in operation in East and South Asia with 25 more under construction and another 40 planned.

In United States, the cost of operating nuclear plants old enough to be highly amortised has improved as a result of increased competition from an average of 2.7 US cents/kWh in 1993 to about 1.6 US cents/kWh by 2000.[2] That is a difference of around US$ 130 million per year for an average station. Reactors that were sold at bargain prices turned into profit centres in the hands of competent operators. Today one-fourth of the 104 licensed reactors in the United States have gained license extensions and all the rest are expected to apply for extensions in the future. Improved economic efficiency together with the need to diversify energy sources with alternatives that do not emit greenhouse gases has prompted the government to offer financial assistance in the form of tax breaks to stimulate the construction of new plants.

In Europe, market liberalisation has also increased the worth of efficient nuclear plants. In Sweden, Germany, The Netherlands and Belgium, politically inspired nuclear phase-out plans are now in question as these countries face the problem of finding replacement power that would meet rising demands and reduced carbon emissions at a cost that will not overwhelm their economies. Orders for new plants were placed in December of 2003 in Finland, and in the fall of 2004 in France; marking the first firm proposals for new nuclear plants in Western Europe since the mid 1980s.

But uncertainties and unresolved issues remain for nuclear power. There are concerns about safety, investment costs and waste disposal. Safety has always been a public concern when it comes to nuclear reactors after the accident at Chernobyl. The industry is still fighting a legacy of fear about accidents and radiation that has been complicated recently with new post 9/11 concerns about plant security and risk of proliferation. Investment risks are high for nuclear plants as it is perceived that the cost of a new plant is still not competitive with baseload alternatives such as coal; and with the upheaval of deregulation, many investors are wary of capital investments exceeding three to four years. In terms of waste disposal, the public remains sceptical. Waste disposal will continue to be controversial until the first geological repositories become operational and the disposal technologies are fully demonstrated.

Energy consumption, for its part, continues to grow worldwide at an accelerated pace, particularly in APEC. Global energy demand is expected to rise to twice or thrice its present level by the first half of this century. At the same time, there is uncertainty about the availability of energy sources to cope with that growth. The production of oil will likely reach its peak around mid-century and will thereafter start its decline. Natural gas resources will last longer, but by mid-century might also be in high demand with unpredictable effects on their prices. Unconventional resources of oil and gas (shale oil, methane hydrates) may have a contribution but to what extent is not clear. For renewable energies and energy storing systems there is also huge uncertainty as to the extent to which they can actually be deployed. Coal may remain one of the few large energy resources available but controlling its adverse impact on the environment either by clean burning technologies or carbon sequestration might be costly to implement.

[2] Ryan (2004).

As for controlling the effects over the environment, experts have suggested that the contribution from fossil fuels to global energy should be limited to no more than 30 percent by the year 2050 to stabilise the concentration of greenhouse gases in the atmosphere to double the preindustrial levels. This would imply that currently known sources that do not emit greenhouse gases such as renewables and nuclear energy, would have to grow by a factor of about 15 from year 2000 levels for this to happen or by a factor of 50 if nuclear power is excluded.

In this context it is worthwhile to investigate what possible role nuclear energy can play in the future of electricity producing systems in APEC and the world, and examine the key factors that will influence that role. What conditions are required in terms of costs, incentives and construction times for the economics of new plant construction to allow a forthright expansion? Are there enough nuclear fuel resources to allow nuclear generation to continue in the fuel mix for the next 50 to 100 years? What will be the implications in terms of fuel prices and energy production costs? What are the expectations for highly radioactive waste management and disposal in the future?

And finally, what paths will nuclear energy development take in the APEC region in the next 50 years? With what we know now, is there more likelihood of nuclear power in APEC of following a stagnation and final decline trend? Or given the characteristics of the region is it more likely for nuclear power to follow a moderate rate of expansion, or even a highly prominent one? And what would the effects of these be on the power production systems of the region?

These are some of the answers we try to answer in the present report, which we also hope will contribute to the dialogue about the future of energy systems in APEC. In doing this report, APERC recognises and respects the position of some APEC member economies to whom nuclear power is not an option for their future.

STUDY SCOPE AND OBJECTIVES

The study's objective is to describe the existing nuclear policies in member economies in APEC and investigate the role of nuclear power in the APEC region over the next 50 years, the impacts of that role and the key factors affecting that role.

In order to do that, the study first examines the current policies for nuclear power in APEC economies as well as their plans for the future, and includes an analysis to identify the drivers that make APEC the region in the world with the largest concentration of nuclear plants and with the most aggressive plans for expansion. We then take a closer look at some of the issues that will influence the way nuclear power evolves in the future. Considered are the economic competitiveness of new nuclear power plants, the availability of uranium fuel resources, and the implementation of final disposal repositories for high-level radioactive waste.

With that information in hand, projections for the future in APEC are then made. Three scenarios for the future of nuclear power are defined, roughly corresponding to cases of low expansion in Asia and decline elsewhere; a moderate expansion in all nuclear economies and including others new to the nuclear industry; and a high expansion case reflecting the most optimist expansion plans from all nuclear economies and incorporating even more economies new to nuclear plants. The impacts of each case on fossil fuel demand and carbon dioxide emissions are afterwards estimated.

OUTLINE OF THE REPORT

The report begins in the first chapter by giving an overall picture of APEC's position in terms of nuclear power relative to the world and continues with a description of the nuclear power programmes and policies existing in APEC member economies. Chapter 2 follows by making an analysis of the policies described previously in Chapter 1 and defining the factors that drive the existence of nuclear power in the economies of the region.

The following three chapters of the report focus on issues that will have influence in the future development of nuclear power in APEC and the world. Chapter 3 examines the standing of nuclear power's economic competitiveness at present and the expectations for the near future. It discusses the impact of investment costs on the overall cost of nuclear power generation and looks into what overall generation costs are likely to be for new plants to be constructed in the future.

Chapter 4 summarises the situation of world nuclear fuel resources and shows what the probable rate of depletion will be for the next 50 years along with the impact on future uranium prices. Chapter 5 is intended to dispel common misconceptions regarding nuclear waste management and describes the current state of the matter, assessing at the same time the challenge it poses for economies in the APEC region. The chapter concludes with a brief discussion on possibilities for international collaboration.

Finally, Chapter 6 shows three likely scenarios for the evolution of nuclear power development in the APEC region in the first half of this century. The Chapter then focuses on the analysis of the possible impacts the different paths will have on alternative fuel consumption, energy security and CO_2 emission avoidance.

SECTION 1

POLICIES

CHAPTER 1

NUCLEAR POWER POLICIES IN THE APEC REGION

CURRENT STATUS OF NUCLEAR POWER IN THE APEC REGION

Asia is the only region in the world where there has been significant growth of nuclear power in the recent past and that currently has sizeable plans for the construction of more nuclear plants. In Asian economies including China, Chinese Taipei, Japan, Korea, Russia, and non-APEC North Korea, India and Pakistan, a total of 28 reactors have been put into commercial operation since 1995 and 25 more are under construction.[3] Thus the APEC region, that includes 5 of these Asian economies plus Canada, Mexico and the United States, is set to become the most influential geographical region in the future of world nuclear development.

Table 1 Recent nuclear reactor additions and reactors under construction in Asia, as of April 2004

Economy	Number of operating reactors	Connected since 1995	Under Construction
China	9	6	2
Chinese Taipei	6	-	2
Japan	53	5	2
Korea	19	10	5
North Korea	-	-	1
Russia	30	1	5
India	14	5	8
Pakistan	2	1	-
Total	133	28	25

Source: IAEA (2004a).

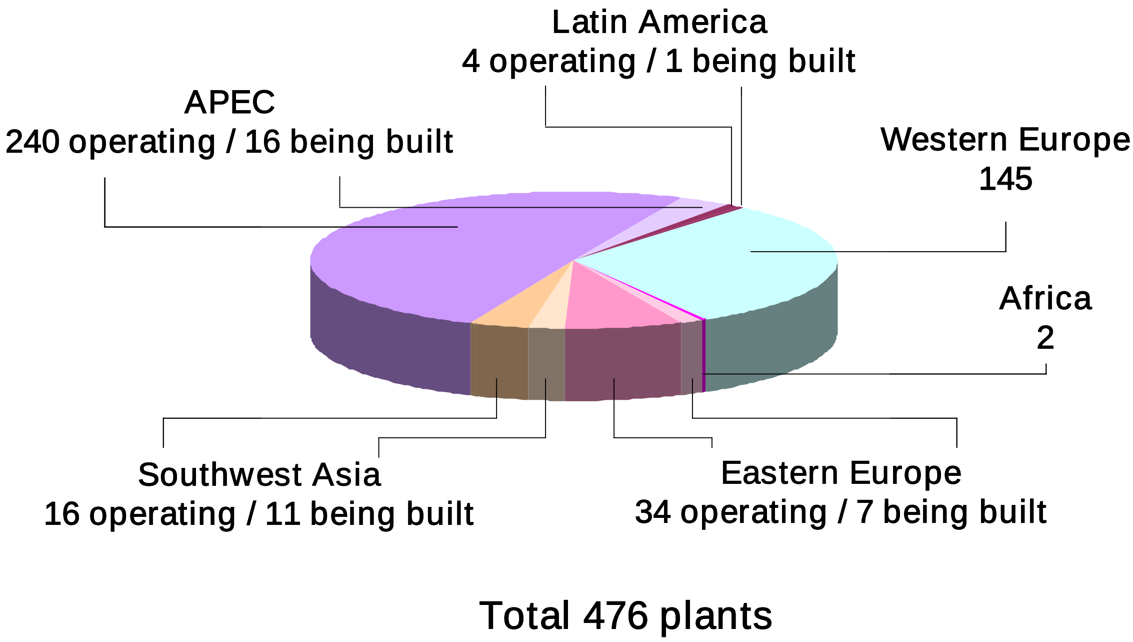
Thirty economies in the world today operate nuclear reactors for electricity generation, with a total of 441 commercial nuclear reactors having a net installed capacity of 363 gigawatts (GW). Of these, 240 reactors are in APEC totalling 205 GW of net capacity (216 GW gross), or 56 percent of the world total.[4] Figure 1 shows the distribution of reactors in the world including APEC, and Figure 2 shows the distribution of APEC's 240 operating reactors.

In addition to power reactors, there are a total of 165 research reactors in 16 APEC member economies. Those economies without commercial reactors that operate research reactors include Australia, Chile, Indonesia, Malaysia, Peru, Philippines, Thailand and Vietnam. Research reactors are used for nuclear research in a number of fields such as health, agriculture, materials research, radiation research and others, and having them does not necessarily indicate an interest on the part of the host economy in pursuing nuclear power electricity generation. Only Brunei Darussalam, Hong Kong, New Zealand, Papua New Guinea and Singapore in APEC are without any research reactor.

[3] All information regarding existing and planned nuclear plants in this report is current as of April, 2004 unless otherwise noted.

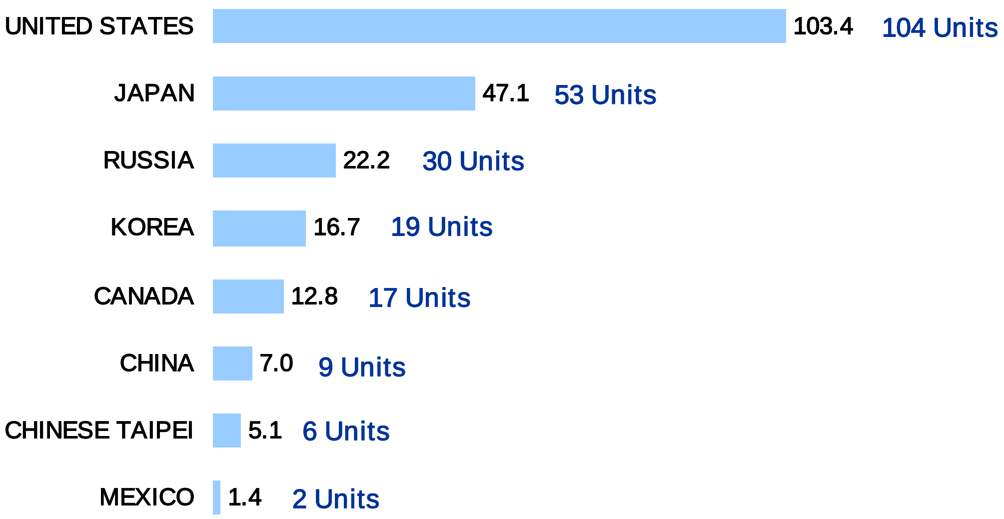
[4] IAEA (2004a).

Figure 1 Nuclear power plants in the world by region



Source: IAEA (2004a).

Figure 2 Nuclear power installed capacity and number of units in APEC, as of April 2004 (GW gross)



Source: IAEA (2004a).

In 2003, commercial nuclear reactors in APEC generated 1,415 terawatt-hours (TWh) of electricity, or 16 percent of the total power produced there.[5] Figure 3 shows the increase of nuclear generation from 1960 up to 1999 in APEC nuclear economies. From 1970 up to 1999 the average annual growth rate of nuclear electricity generation in APEC was an impressive 14 percent.

Table 2 List of nuclear research reactors in APEC member economies

Economy	Operational	Shut down	Decommissioned	Under construction	Planned
Australia	1	1	1	0	1
Canada	8	5	3	2	1
Chile	2	0	0	0	0
China	14	2	0	1	1
Indonesia	3	0	0	0	1
Japan	16	5	3	0	0
Korea	2	2	0	0	0
Malaysia	1	0	0	0	0
Mexico	3	0	1	0	0
Peru	2	0	0	0	0
Philippines	0	1	0	0	0
Russia	57	28	11	1	0
Chinese Taipei	2	2	2	1	1
Thailand	1	0	0	1	0
United States	52	107	68	0	0
Vietnam	1	0	0	0	0
Total	165	153	89	6	5

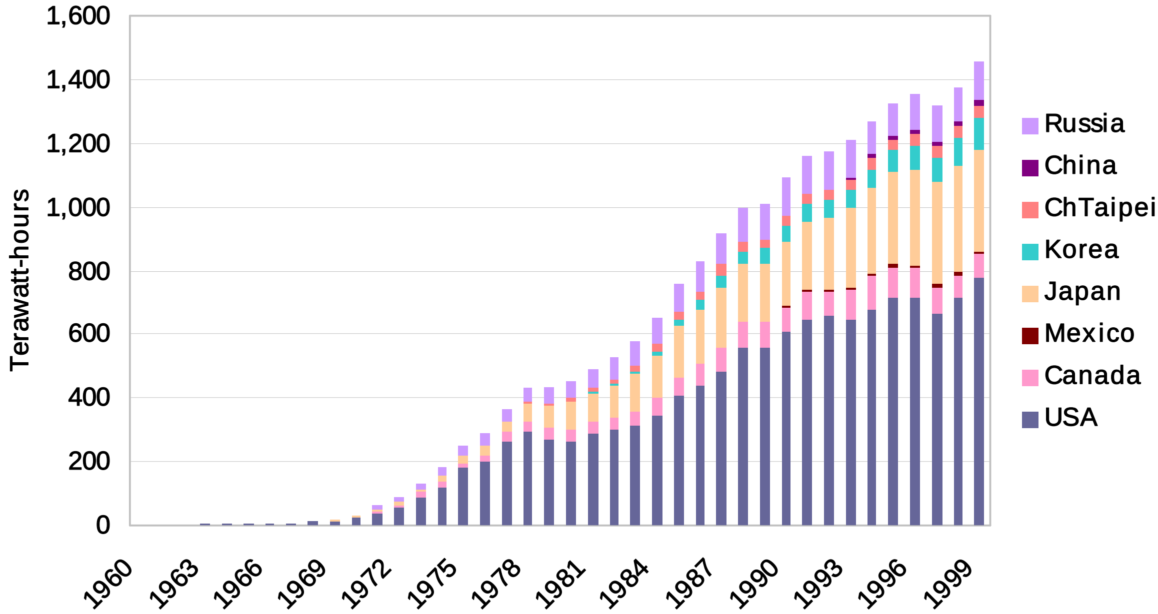
Source: IAEA (2004c).

Twenty economies in the world depend on nuclear energy for 20% or more of their electricity generation, and four of those economies are in APEC. Figure 4 shows the world economies that generate 20 percent or more of their electricity using nuclear means, and also shows the relative standing of all the APEC nuclear economies using data from 2003. Marked in pink are the four economies in APEC that have a nuclear share of more than 20 percent in their total power generation: Korea, Japan, Chinese Taipei and the United States. The same figure shows Japan with a nuclear share in generation of 25 percent, which is low compared to its more typical share of around 30 percent observed in previous years. The year 2003 in Japan saw a low participation of nuclear power as a result of the shut down for inspections of more than 17 reactors (see the section on Japan in this Chapter).

In general in the APEC region, the bulk of the nuclear capacity additions took place during the seventies and the eighties, and the largest share of this increase happened in the United States. A full 80 percent of the reactors operating in the world today were constructed during that period, while in APEC that figure is 85 percent. As can be seen in Figure 5, United States' contribution to additions dominates the region. Also evident in the figure is the contrast between the additions after 1990 in the United States and in Japan. United States has virtually no additions after that date while Japan's recent reactor additions have remained at approximately the same rate as during the decade of the eighties.

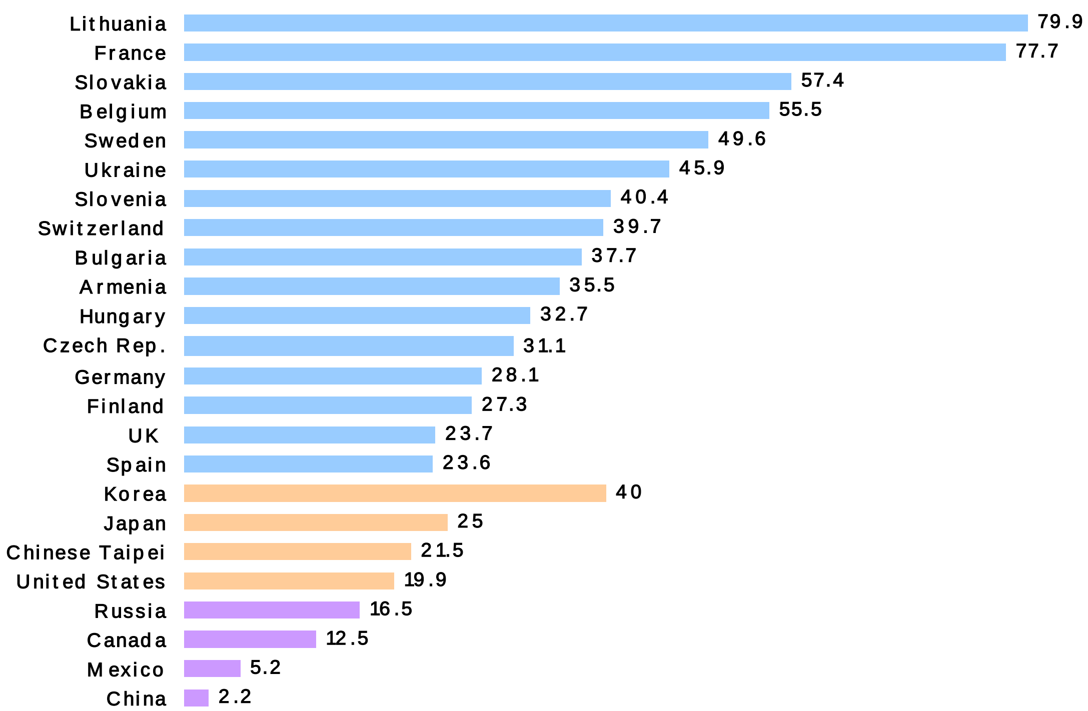
[5] IAEA (2004a).

Figure 3 Nuclear generation in APEC economies, 1960-1999 (TWh)



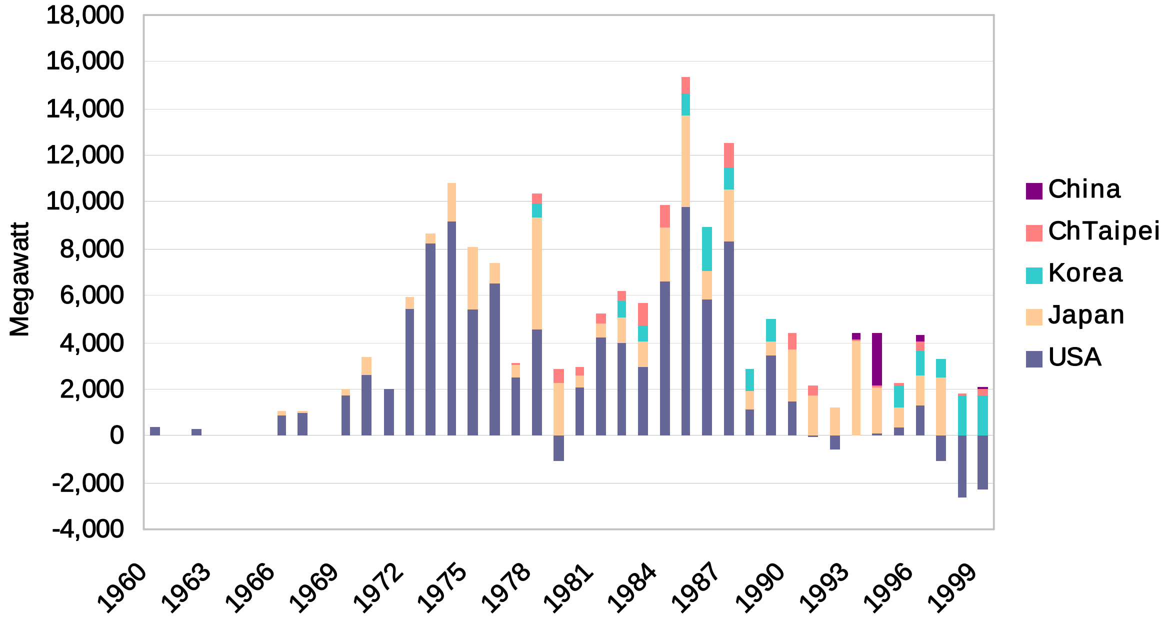
Source: APERC (2002).

Figure 4 Nuclear share in total power generation, 2003 (Percentage)



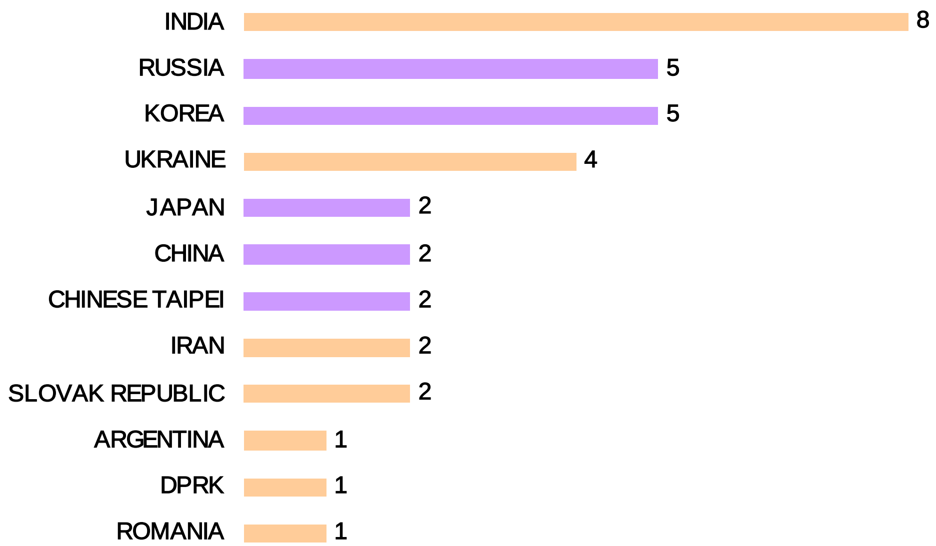
Source: IAEA (2004a).

Figure 5 Capacity additions in selected APEC economies, 1960-1999 (MW)



Source: APERC (2002).

Figure 6 Nuclear plants under construction in the world, as of April 2004



Sources: IAEA (2004a), APEC economies.

There are 35 reactors under construction in the world as of April 2004. Out of those, 16 are in the APEC region accounting for an additional 17 GW of capacity. Table 3 lists the official plans as of the same date for new nuclear power plants in economies of the APEC region. There are reasonably firm plans for 34 more reactors in APEC, if only plants planned before the year 2020 are considered. Plants planned after that date or those not considered firm enough are not included in this number.

Table 3 Nuclear reactors planned in APEC economies up to 2020, as of April 2004

Economy	Planned reactors	Comments
China	6 units by 2010	China Atomic Energy Authority plans the construction of 6 units by 2005. China National Nuclear Corporation expects the construction of 6 to 8 units by 2010.[6]
Japan	12 units by 2020	12 units planned by the major electric power companies of Japan.
Korea	8 units by 2015	8 additional units by 2015 according to the 1st Basic Plan of Long Term Electricity Supply and Demand (2002-2015).[7]
Russia	4 units by 2010	4 new units by 2010, and 25 additional reactors between 2010 and 2020 according to the Russian Energy Strategy[8]
United States	2 units by 2010	At least one by 2010 according to the USDOE's Nuclear Power 2010 Initiative; but awards to two utilities, Dominion and Exelon, have been announced to conduct Early Site Permit Scoping Studies.[9]
Vietnam	2-4 units by 2020	2 to 4 units by 2020 are being analysed in pre-feasibility studies of nuclear power in Vietnam.[10]
Total	32 reactors	By 2020

The greatest growth of nuclear power in the APEC region is expected in Korea, China, Japan and Russia. Outside of APEC, India is another Asian nation that is growing fast in terms of nuclear power: with 14 reactors currently in operation, it has 8 reactors under construction and is planning the construction of 25 more before the year 2020.

[6] IEEJ (2003).
[7] MOCIE (2002).
[8] Centre for Energy Policy, Russia (2003).
[9] USDOE (2004).
[10] Institute of Energy of Viet Nam (2003).

NUCLEAR POLICY IN APEC ECONOMIES

In the following pages we detail nuclear power policy in selected APEC economies in the context of their energy sector and electricity system's present structure. The section begins with APEC's 8 economies with nuclear reactors in order of importance pertaining to the number of reactor units in operation. Following that, we summarise policies in APEC economies with no commercial reactors at present.

UNITED STATES

BACKGROUND

The United States is the world's largest and most influential economy and in 2001 it had a GDP per capita of more than US$ 32 thousand (based on purchasing power parity, PPP, and 1995 US$). Economic growth from 1995 to 2000 averaged 3.8 percent annually, but a brief recession slowed it down to 0.3 percent in 2001 and 2.4 percent in 2002. A recovery is beginning to take hold, which is expected to return growth rates to between 3 and 4 percent by 2004.

The United States is the largest producer, consumer and importer of energy in the world and has a large wealth of energy resources. However, it depends by 24 percent on foreign sources for its total primary energy needs. Net primary energy supply in 2001 was about 2,145 Mtoe. The per capita energy consumption of United States in 2001 was 5.5 toe (Final Energy Consumption), nearly four times the APEC average.[11]

Electricity demand between 1980 and 1999 averaged an annual growth rate of 2.6 percent.[12] In 2003, nuclear energy accounted for 20 percent of the total power generation, second only to coal, which has a share of 50 percent. Since the mid-80's, nuclear energy has been the second largest source of electricity generation in the United States.[13]

CURRENT SITUATION OF NUCLEAR POWER

The nuclear power industry in the United States covers most phases of the nuclear fuel cycle: uranium mining, uranium enrichment, fuel fabrication, and waste disposal, but does not include reprocessing. Although the nuclear industry is mostly privately owned, three reactors are owned by the Federal Government and six others are owned by regional agencies.

Table 4 Nuclear power data summary, United States

Reactors in operation	104
Nuclear installed capacity (gross)	103,366 MW
Reactors under construction	0
Total electricity generation	3,846.0 TWh
Nuclear generation	763.7 TWh
Nuclear generation share	19.9%

Note: Generation figures for 2003.
Source: IAEA (2004).

[11] EWG/APERC (2003).
[12] APERC (2002).
[13] EIA (2004a).

Table 5 Nuclear power reactors in operation in the United States

Name	Type	Location	Gross Capacity (MWe)	Date Connected
Arkansas One-1	PWR	Arkansas	903	8/17/1974
Arkansas One-2	PWR	Arkansas	943	12/26/1978
Beaver Valley-1	PWR	Pennsylvania	860	6/14/1976
Beaver Valley-2	PWR	Pennsylvania	923	8/17/1987
Braidwood-1	PWR	Illinois	1,225	7/12/1987
Braidwood-2	PWR	Illinois	1,225	5/25/1988
Browns Ferry-1	BWR	Alabama	1,098	10/15/1973
Browns Ferry-2	BWR	Alabama	1,151	8/28/1974
Browns Ferry-3	BWR	Alabama	1,190	9/12/1976
Brunswick-1	BWR	North Carolina	844	12/4/1976
Brunswick-2	BWR	North Carolina	839	4/29/1975
Byron-1	PWR	Illinois	1,225	3/1/1985
Byron-2	PWR	Illinois	1,225	2/6/1987
Callaway-1	PWR	Missouri	1,250	10/24/1984
Calvert Cliffs-1	PWR	Maryland	865	1/3/1975
Calvert Cliffs-2	PWR	Maryland	870	12/7/1976
Catawba-1	PWR	South Carolina	1,192	1/22/1985
Catawba-2	PWR	South Carolina	1,192	5/18/1986
Clinton-1	BWR	Illinois	1,017	4/24/1987
Columbia	BWR	Washington	1,200	5/27/1984
Comanche Peak-1	PWR	Texas	1,215	4/24/1990
Comanche Peak-2	PWR	Texas	1,215	4/9/1993
Cooper	BWR	Nebraska	791	5/10/1974
Crystal River-3	PWR	Florida	876	1/30/1977
Davis Besse-1	PWR	Ohio	917	8/28/1977
Diablo Canyon-1	PWR	California	1,136	11/11/1984
Diablo Canyon-2	PWR	California	1,137	10/20/1985
Donald Cook-1	PWR	Michigan	1,056	2/10/1975
Donald Cook-2	PWR	Michigan	1,100	3/22/1978
Dresden-2	BWR	Illinois	855	4/13/1970
Dresden-3	BWR	Illinois	851	7/22/1971
Duane Arnold-1	BWR	Iowa	550	5/19/1974
Enrico Fermi-2	BWR	Michigan	1,154	9/21/1986
Farley-1	PWR	Alabama	877	8/18/1977
Farley-2	PWR	Alabama	884	5/25/1981
Fitzpatrick	BWR	New York	882	2/1/1975
Fort Calhoun-1	PWR	Nebraska	500	8/25/1973
Grand Gulf-1	BWR	Mississipi	1,260	10/20/1984
H.B. Robinson-2	PWR	South Carolina	700	9/26/1970
Hatch-1	BWR	Georgia	857	11/11/1974
Hatch-2	BWR	Georgia	965	9/22/1978
Hope Creek-1	BWR	New Jersey	1,070	8/1/1986
Indian Point-2	PWR	New York	1,299	6/26/1973
Indian Point-3	PWR	New York	1,012	4/27/1976
Kewaunee	PWR	Wisconsin	524	4/8/1974
Lasalle-1	BWR	Illinois	1,238	9/4/1982
Lasalle-2	BWR	Illinois	1,241	4/20/1984
Limerick-1	BWR	Pennsylvania	1,138	4/13/1985
Limerick-2	BWR	Pennsylvania	1,138	9/1/1989
McGuire-1	PWR	North Carolina	1,142	9/12/1981

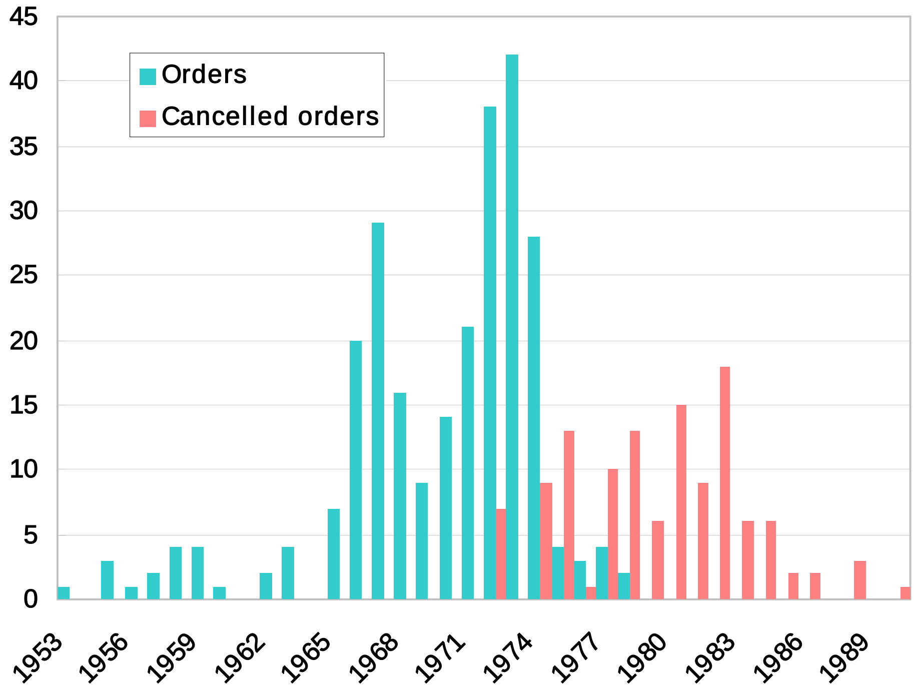
McGuire-2	PWR	North Carolina	1,142	5/23/1983
Millstone-2	PWR	Connecticut	910	11/9/1975
Millstone-3	PWR	Connecticut	1,193	2/12/1986
Monticello	BWR	Minnesota	625	3/5/1971
Nine Mile Point-1	BWR	New York	642	11/9/1969
Nine Mile Point-2	BWR	New York	1,259	8/8/1987
North Anna-1	PWR	Virginia	972	4/17/1978
North Anna-2	PWR	Virginia	964	8/25/1980
Oconee-1	PWR	South Carolina	886	5/6/1973
Oconee-2	PWR	South Carolina	886	12/5/1973
Oconee-3	PWR	South Carolina	886	9/18/1974
Oyster Creek	BWR	New Jersey	641	9/23/1969
Palisades	PWR	Michigan	800	12/31/1971
Palo Verde-1	PWR	Arizona	1,299	6/10/1985
Palo Verde-2	PWR	Arizona	1,299	5/20/1986
Palo Verde-3	PWR	Arizona	1,302	11/28/1987
Peach Bottom-2	BWR	Pennsylvania	1,159	2/18/1974
Peach Bottom-3	BWR	Pennsylvania	1,159	9/1/1974
Perry-1	BWR	Ohio	1,253	12/19/1986
Pilgrim-1	BWR	Massachusetts	691	7/19/1972
Point Beach-1	PWR	Wisconsin	529	11/6/1970
Point Beach-2	PWR	Wisconsin	531	8/2/1972
Prairie Island-1	PWR	Minnesota	557	12/4/1973
Prairie Island-2	PWR	Minnesota	556	12/21/1974
Quad Cities-1	BWR	Illinois	806	4/12/1972
Quad Cities-2	BWR	Illinois	819	5/23/1972
R.E. Ginna	PWR	New York	508	12/2/1969
River Bend-1	BWR	Louisiana	1,036	12/3/1985
Salem-1	PWR	New Jersey	1,170	12/25/1976
Salem-2	PWR	New Jersey	1,170	6/3/1981
San Onofre-2	PWR	California	1,127	9/20/1982
San Onofre-3	PWR	California	1,127	9/25/1983
Seabrook-1	PWR	New Hampshire	1,207	5/29/1990
Sequoyah-1	PWR	Tennessee	1,160	7/22/1980
Sequoyah-2	PWR	Tennessee	1,155	12/23/1981
Shearon Harris-1	PWR	North Carolina	951	1/19/1987
South Texas-1	PWR	Texas	1,310	3/30/1988
South Texas-2	PWR	Texas	1,310	4/11/1989
St. Lucie-1	PWR	Florida	872	5/7/1976
St. Lucie-2	PWR	Florida	882	6/13/1983
Surry-1	PWR	Virginia	849	7/4/1972
Surry-2	PWR	Virginia	854	3/10/1973
Susquehanna-1	BWR	Pennsylvania	1,128	11/16/1982
Susquehanna-2	BWR	Pennsylvania	1,168	7/3/1984
Three Mile Island-1	PWR	Pennsylvania	837	6/19/1974
Turkey Point-3	PWR	Florida	726	11/2/1972
Turkey Point-4	PWR	Florida	726	6/21/1973
Vermont Yankee	BWR	Vermont	531	9/20/1972
Virgil C. Summer-1	PWR	South Carolina	1,003	11/16/1982
Vogtle-1	PWR	Georgia	1,202	3/27/1987
Vogtle-2	PWR	Georgia	1,203	4/10/1989
Waterford-3	PWR	Louisiana	1,200	3/18/1985
Watts Bar-1	PWR	Tennessee	1,183	2/6/1996
Wolf Creek	PWR	Kansas	1,188	6/12/1985

Source: IAEA (2004a).

United States at present has 104 licensed reactors, although Brown's Ferry unit 1, still holding a license, has not operated since 1985 and has plans to restart until 2007. Most of the installed nuclear capacity in the United States today was constructed during the 1970s and 80s as a result of an overconfidence in nuclear fuel and operating costs as compared to coal and other sources of electricity, even though by then there was little experience with the operation of reactors. A contributing factor afterwards was the need to diversify energy sources after the oil shocks of 1973 and of 1979-80. The Nixon administration announced around that time that the United States would pursue energy independence through increased reliance on nuclear energy, which would account for roughly 40 percent of electricity production by 1990.[14]

Most of the orders for new reactors in the United States were placed in the period between 1965 and 1974, with the largest number of orders, 42, being placed in 1973. The fast pace of construction during this period made nuclear the second largest source of power generation to this day. It was around 1975 that cancellations of new orders began to take place.[15] High capital and licensing costs, the unpredictability of construction times and the difficulty of depreciating capital costs made utilities realise that nuclear power was far from an economic alternative for the times. Nuclear plants typically operated at 70 percent capacity during this market-regulated era, where there was no incentive to increase efficiencies to the levels of today. This slow rate of electricity production together with caps on electricity prices lengthened the time required to depreciate capital costs, therefore called stranded costs. As well, a decrease in electricity demand after the economic slowdown and efficiency policies resulting from the oil shocks of the 1970s made utilities rethink their expansion and construction plans.

Figure 7 Number of orders and cancelled orders for nuclear reactors in the United States, 1953-1990



Source: EIA (2003b).

As a result, orders started to be cancelled long before 1979, the year of the event at Three Mile Island. Between 1972 and 1979, altogether there were 59 cancellations, almost the same as after 1979 (62 cancellations between 1980 and 1990, Figure 7). The addition of new capacity corresponding to

[14] Jasper (1990).

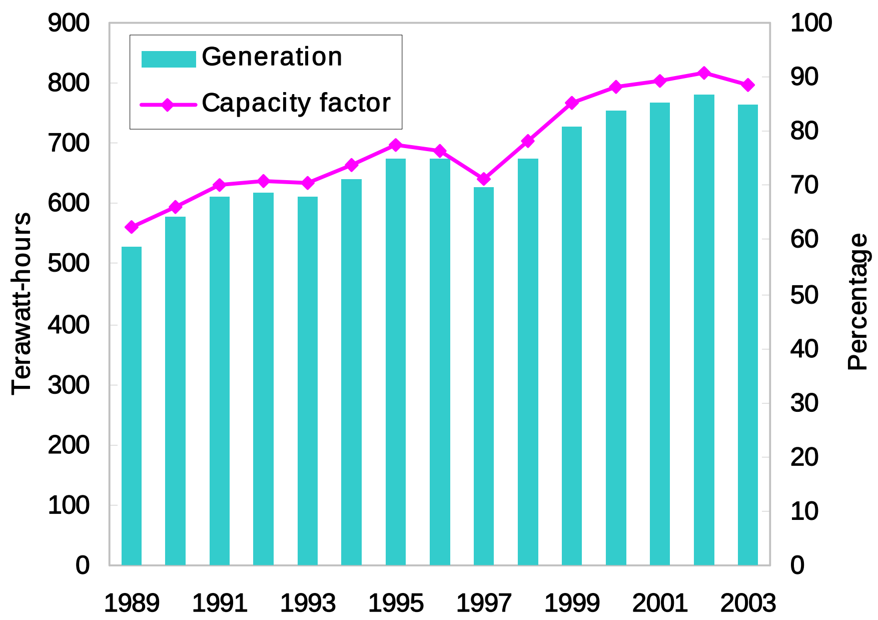
[15] Jasper (1990).

orders still in place continued strongly during the decade from 1980 to 1989 as can be seen in Figure 9. The latest reactors to be constructed entered commercial operation in the 1990s: Seabrook in New Hampshire in 1990 with 1,207 MW; Comanche Peak 1 in Texas also in 1990 with 1,215 MW; Comanche Peak 2 in 1993 with 1,215 MW; and Watts Bar in Tennessee in 1996 with 1,183 MW.

One of the repercussions of Three Mile Island was the establishment of retrofit requirements by the United States Nuclear Regulatory Commission (NRC). Plants under construction at the time were required to install retrofits, sending construction costs soaring and exacerbating the already poor economic competitiveness of nuclear plant operation. Cancellations by the utilities continued in the following years and since 1979 no new orders for nuclear reactors were placed in the United States.

Even though Three Mile Island was an important influencing factor on the general public's perception of nuclear power, these facts show that the major reason for the decline in construction of new reactors was poor economic competitiveness of the technology given the conditions at the time, both prior and after that incident.

Figure 8 Nuclear plant output and capacity factor in the United States, 1989-2003

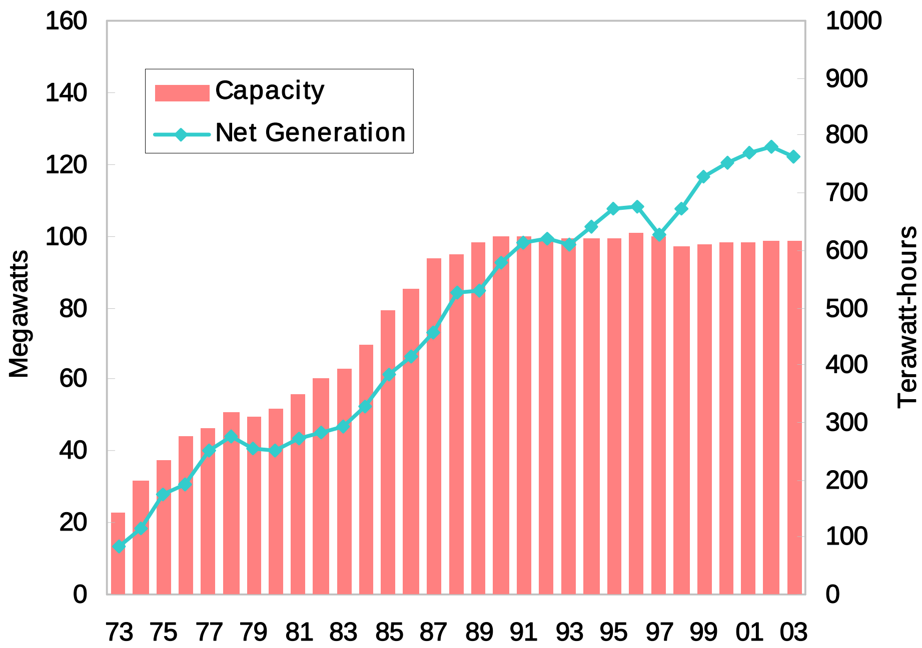


Source: EIA (2004a).

Over the past 20 years in the United States, however, nuclear plants have achieved ever-higher safety and performance parameters. Competition has made operators try to maximise generation as much as possible and the average capacity factor for nuclear plants in the United States, or the percentage of power generated by a plant over a year as compared to the possible total, has increased from 58.5 percent in 1980 to a high of 90.9 percent in 2002 (it diminished slightly to 84 percent in 2003, Figure 8). This in turn is for the most part the result of reducing refuelling outages (the time a plant is stopped for fuel changes), and reducing also the number of unplanned shutdowns. Refuelling outages have been reduced from 100+ days in 1980 to 37 days in average in 2003. The goal for unplanned shutdowns or scrams was to achieve 1 event for every 7,000 hours of reactor operation by the year 2005, but the average for U.S. reactors has been below 1 since 1995.[16] Having a low number of scrams is a reflection of the effectiveness of programmes designed for improved operations, engineering, maintenance and training.

[16] Nuclear Energy Institute.

Figure 9 Nuclear capacity and generation in the United States, 1973-2003



Source: EIA (2004a).

As a result (Figure 9), nuclear generating capacity between 1990 and 2002 increased by 200 TWh solely by the improvement in capacity factors, without the construction of new reactor units (except for uprates). This is an increase of 35 percent; equivalent to 25 new 1,000 MW reactors.

NUCLEAR POWER PRODUCTION COSTS IN THE UNITED STATES

With higher performance parameters, low fuel costs, and plant cost depreciation out of the way in a majority of cases, nuclear plants in United States have achieved lower production costs than all other competing facilities except hydro, assuming the position of baseload generation cost leader for fourth year in a row in 2002. Production costs including only fuel plus operation and maintenance averaged 1.71 US cents/kWh at nuclear plants in 31 states (Table 28 in Chapter 2). The comparable costs for coal-fired plants averaged 1.85 cents/kWh, for natural gas plants 4.06 cents/kWh and for oil-fired plants 4.41 cents/kWh. [17]

All these improvements in performance parameters and operating costs have brought about the restart of several idled reactors and prompted the lifetime extension of others since 1998. By May 2003, sixteen licenses had been renewed to allow for extended operation, 14 licenses were under review, and 18 new applications were expected by the end of the same year.[18] In all, it is expected that at least 80 percent of operating nuclear plants in the United States will apply for extensions of their lifetime.[19]

Another result of the better financial position of nuclear plants in the United States is nuclear plant uprates. Uprates are internal modifications to nuclear plants to increase their power generating capacity by 7-20 percent. With uprates a plant owner can increase its generating ability without the difficulties in licensing and the publicity generated by the building of a new plant. Uprates have been used by utilities in the United States since 1970 and as of July 2004 they have contributed 4,000 MW

[17] NEI (2003b).

[18] NEI (2003b).

[19] Grimston & Beck (2002).

of additional capacity, or the equivalent of 4 new nuclear plants. More uprates are expected in the next 5 years, for an additional 1,000 MW. [20]

The deregulation of the electric power industry has resulted in changes of ownership for all types of electric generation assets, and the same phenomenon applies to nuclear plants. A tendency is emerging for owners to focus on one aspect of the power industry. Companies that specialise on nuclear energy are purchasing nuclear plants, and nuclear operating companies are forming to run plants owned by different companies. With consolidation, economies of scale can be achieved as specialisation of activities can lead to greater performance and to further cost savings.

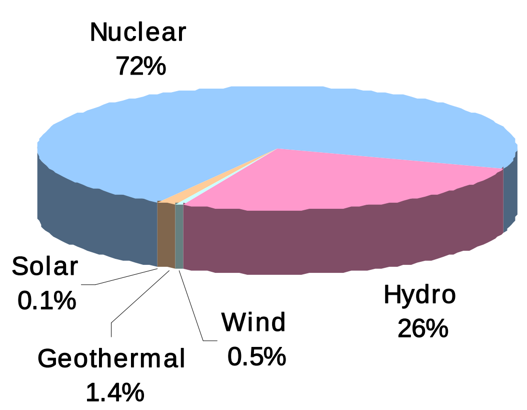
UNITED STATES NUCLEAR POWER POLICY

The National Energy Policy of May 2001, identifies nuclear energy as a major component of the United States' national policy, and makes recommendations for its expansion. For many years the United States Department of Energy (USDOE) was not outspoken in promoting nuclear energy given its economic performance especially after the regulatory changes brought about by the Three Mile Island incident. Now it is seen as an important component of the energy portfolio mainly as a way to diversify energy sources in power generation and improve energy security.

The USDOE is revitalising research in nuclear energy after funding was nearly eliminated for this purpose in 1998. In 2002, the USDOE spent US$ 105.5 million in nuclear research. In a recent statement by the USDOE's Office of Nuclear Energy to the House of Representatives[21], the USDOE requested a total of US$410 million for investment in 2005 in nuclear research, development and infrastructure. Funds would be used in the following main programmes which concentrate the USDOE's efforts for a re-emergence of nuclear power:

- Nuclear Power 2010.
- Generation IV Nuclear Energy Systems.
- Advanced Fuel Cycle Initiative.
- Nuclear Hydrogen Initiative.

Figure 10 Structure of emission-free electricity generating sources in the United States



Source: USDOE (2002).

[20] NRC (2004).

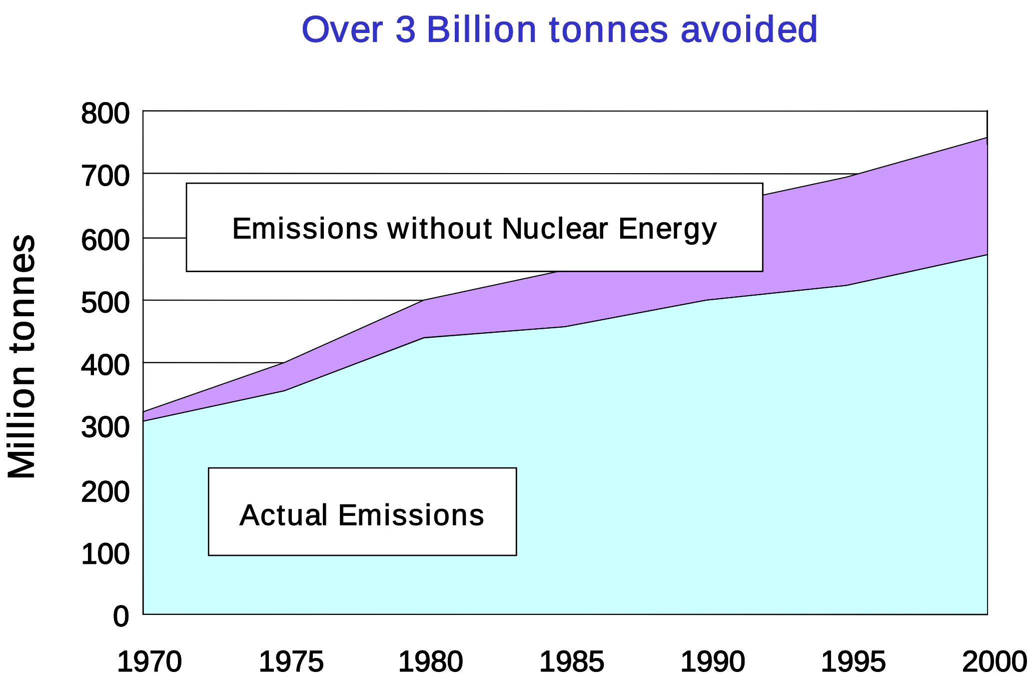
[21] USDOE (2004b).

The USDOE sees nuclear energy as a proven technology but with important issues to be resolved.[22] In the case of oil, the USDOE mentions that 51 percent of United States' needs is imported and is vulnerable to supply disruptions and price fluctuations. Natural gas is the nation's choice of fuel today, but it carries an uncertainty as to the stability of prices in the future and as to the resources available to the nation. Further, it is not known at the moment if investors would support large base-load plants using natural gas. Coal is seen as plentiful but polluting by the USDOE and renewable sources are seen as not having the capacity to meet the large demand of energy foreseen and as an expensive proposition still.

Nuclear energy is also seen as an important contributor to the environmental policy of the United States. The National Energy Policy states that since 1970, energy consumption has risen by 42 percent while key air emissions have declined by 31 percent. This in part is due to the fact that around 30 percent of the electricity supply is generated by emission-free sources such as nuclear, hydropower and renewable energies. Out of all the sources contributing to clean electricity generation, nuclear power contributes with three-quarters. The USDOE estimates that nuclear power avoids about 175 million tonnes of carbon each year.[23]

In June 3rd, 2004 a resolution was introduced by the House of Representatives that would assert the U.S. Congress' recognition of the essential role of nuclear power in the national energy policy of the United States and would affirm its support for the increased use of nuclear power and the construction and development of new and improved nuclear power generating plants as a means of contributing to national energy independence and maintaining a clean environment.

Figure 11 CO_2, SOx and NOx air emissions from electricity generation in the United States, 1970-2000 (Million tonnes)



Sources: NEI, US EPA, EIA/USDOE.

[22] USDOE (2002).

[23] NEPD (2001).

NUCLEAR POWER 2010 PROGRAMME

Unveiled by the Secretary of Energy on February 2002, it proposes the deployment of new baseload nuclear generating capacity in support of the National Energy Policy. It is a joint government/industry cost-shared effort to identify sites for new nuclear plants, develop advanced nuclear plant technologies, and demonstrate new regulatory processes leading hopefully to the construction of new reactors around 2010 following 25 years of no new orders.

The programme bases its proposal on the projection that by 2020 the United States would need 393 GW of new generating capacity, equal to approximately 1,300 to 1,900 new power plants, or a rate of 60 to 90 plants per year. The programme calls for existing plants to increase their production either by power uprates or to extend their lifetimes by way of license extensions. The USDOE expects a fraction of the needed capacity to be nuclear baseload plants, and assumes that competitive advanced reactor designs with prices in the range of US$1,000 to 1,200 per kW can become available to the commercial market through regulatory demonstration and reactor technology development activities. A Roadmap to Deploy New Nuclear Power Plants in the United States by 2010 recommends actions to be taken by the industry and the USDOE to support the programme and establishes a phased plan of action to achieve near-term deployment of new advanced nuclear plants. Major phases are the Regulatory Demonstration phase and the Technology Development phase. The regulatory tasks include the demonstration of the Early Site Permit (ESP) and combined Construction and Operating License (COL) processes to reduce licensing uncertainties and minimize the attendant financial risks to the licensee. The technology development activities support research and development to finalize and certify those advanced reactor designs which United States power generation companies are willing to build.

US$10 million were included in the request for R&D funds to support activities associated with achieving NRC approval of early site permits and the development of Combined Construction and Operating License applications. Part of the funds will also be used to continue to evaluate and develop strategies to mitigate specific financial risks associated with the deployment of new nuclear plants.

The USDOE invited proposals in November 2003 from power companies to initiate nuclear plant licensing demonstration projects. Under these cost-shared projects, power companies will conduct studies, analyses, and other activities necessary to select an advanced reactor technology and prepare a site-specific, technology-specific Combined Operating License application. These projects will lead to the design certification by the NRC of a standardised nuclear power plant design. By April 2004, three consortia had responded to the initiative: one led by Virginia-based Dominion, another led by the Tennessee Valley Authority, and NuStart Energy Development LLC.

The first consortium filed its proposal in March 2004 and is led by Dominion. Other participants include: AECL Technology; Atomic Energy of Canada Ltd.'s (AECL) American subsidiary; Bechtel Power Corp.; and Hitachi America. The reactor technology to be investigated by this group is the ACR 700, an advanced CANDU concept being developed by AECL.

Another consortium is led by the Tennessee Valley Authority (TVA) and is made up of Bechtel Power Corp., Global Fuel-Americas, USEC Inc., and reactor vendors General Electric and Toshiba. Their proposal will examine building a reactor in northern Alabama at TVA's Bellefonte nuclear site. The reactor technology being evaluated is the GE advanced boiling water reactor marketed under a joint agreement with Toshiba.

The last consortium to respond as of April 2004 is NuStart Energy Development LLC, which includes the participation of Constellation Energy Group, Duke Energy, EDF International North America, Entergy Nuclear, Exelon Generation, Southern Co., the Tennessee Valley Authority and two nuclear vendors: Westinghouse Electric Co. and GE Energy nuclear operations. The consortia have selected the General Electric ES Boiling Water Reactor and the Westinghouse Advanced Passive

1000 as the reactor designs for the project. After approval of the process by the NRC, any individual company or group of companies could decide to use the license to build a new plant.[24]

GENERATION IV NUCLEAR ENERGY SYSTEMS

The Generation IV International Forum was established by the USDOE to develop advanced reactor technologies for commercial deployment in the 2015 to 2030 timeframe. It now has eleven members: Argentina, Brazil, Canada, the European Union, France, Japan, Korea, South Africa, Switzerland, the United Kingdom and the United States. The Forum has selected 6 reactor systems as the most viable for further research. The members are now organised into interest groups associated with each of the six systems.

The technology goals for next generation reactors as established by the Forum are to:

- Provide sustainable energy generation and effective fuel utilisation
- Minimise nuclear waste and reduce the long-term stewardship burden
- Be more proliferation resistant
- Have improved safety and reliability
- Have low probability of reactor core damage
- Eliminate the need for offsite emergency response
- Have lower life-cycle costs and lower financial risks compared to other energy sources

In the United States, the Generation IV Program of the DOE was funded at US$10 million in 2003.

ADVANCED FUEL CYCLE INITIATIVE

The activities in this initiative are geared towards processing spent nuclear fuel from reactors. Its aim is the development of proliferation-resistant treatment and transmutation technologies that can reduce the volume and the toxicity of spent nuclear fuel. With these technologies, it is desired to reduce inventories of commercially produced plutonium while at the same time recovering unburned material in spent nuclear fuel for additional energy.

Results have proven the ability of the so-called UREX technology to separate uranium from spent fuel at high purity levels. A derivative of the process, called UREX+, separates a mixture of plutonium and neptunium that can be used as a basis for a type of proliferation-resistant fuel for light water reactors. These efforts are important in reducing the volume and radioactivity of high level waste and in reducing the inventory of plutonium by enabling its use as fuel in existing light water reactors or advanced reactors.

What makes this research in reprocessing technologies different to previous efforts, is that these technologies are tied to specific nuclear reactor systems being developed in the Generation IV initiative, particularly those that produce very high energy neutrons that would be needed to transmute a wide variety of toxic radioactive species. The work is being carried out through a coordinated effort with the national laboratories, universities and foreign institutions.

NUCLEAR HYDROGEN INITIATIVE

Hydrogen is being seriously considered by the USDOE as a future technology to replace other fuels mainly in the transportation sector, reducing the United States' dependence on foreign sources of petroleum and thus enhancing national security. At the same time, nuclear energy is considered to be a cornerstone in this hydrogen policy for the future. The goal of the Nuclear Hydrogen Initiative

[24] NEI (2004a).

is to develop economic, commercial-scale production of hydrogen using nuclear energy. The USDOE believes that the use of very-high temperature reactors coupled with thermo-chemical or high-temperature electrolytic water disassociation processes offer a more efficient technology for production of large quantities of hydrogen without release of greenhouse gases.

PRICE-ANDERSON ACT

The Price-Anderson Act authorizes methods of insuring the public for damages from nuclear accidents. It is considered an essential legislation that has allowed the construction of nuclear plants in the United States by, on the one hand, ensuring that enough money is available to pay for liability claims, and on the other, putting a limit on liability to protect utilities and manufacturers against excessive claims. Currently the U.S. public has more than $10 billion of insurance protection in the event of a nuclear reactor incident. The Act also establishes the coverage system, which is privately funded and in which neither the federal government nor the taxpayers are required to make up for any deficiencies in coverage.

The Price-Anderson Act was originally passed by Congress in 1957 and afterwards 10-year extensions of the law were also passed in 1967, 1975, and a 15-year extension in 1988. With each extension came the introduction of revisions or amendments. In February of 2003, Congress extended the coverage for commercial nuclear facilities through December of that year, and for USDOE facilities through December 2004 in a separate legislative action.

Due to the importance of this legislation for the eventual construction of new reactors in the United States, Congress is considering a renewal of the law as part of comprehensive energy legislation. The new legislation being proposed would extend the current law and ensure that the indemnification programme for commercial power reactors will be available for new plants constructed after December 2003, although all reactors built before that date continue to be covered until they are decommissioned.

NUCLEAR WASTE POLICY

In United States, the Federal Government, not the nuclear plants, is responsible for long-term storage or disposal of spent nuclear fuel, which is the same as high-level radioactive waste. As for low-level waste, every state is required to provide for disposal, either alone or in cooperation with other states. The Waste Policy Act of 1980 actually encourages the formation of regional interstates compacts for waste disposal.

Recycling of commercial nuclear fuel was banned by the Carter administration in 1979 to address concerns about the possibility of nuclear weapons proliferation. Even though the Reagan administration lifted the ban on reprocessing in 1981, non-proliferation concerns continue to guide United States' spent fuel policy. As mentioned before, reprocessing could be an integral and necessary component of one of the new generation reactor systems being considered for development by the USDOE.

The plan of the Federal Government for the nation's spent nuclear fuel is to dispose of it in a deep geologic repository. The Nuclear Waste Policy Act of 1982 calls for the creation of a federal integrated radioactive material management system that would consist of two key elements:

a) an underground repository that would permanently isolate and permit monitoring of used nuclear fuel, and

b) a safe, efficient transportation system to move used fuel to the repository.

After considering different sites, Yucca Mountain in Nevada was selected as the site for this repository. The process of final certification and construction of the site has included: the approval of the USDOE's recommendation of the Yucca Mountain site for the repository by the Bush administration in February, 2002; the approval by the House of Representatives of the site in May of the same year over the objection introduced by the State of Nevada; and the approval by the U.S. Senate of the site on July of 2002.

Now the USDOE will file applications to the Nuclear Regulatory Commission to obtain construction and operation licenses for the repository. The United States together with Sweden and Finland are the three most advanced nations in terms of site selection and commissioning activities for a final high-level commercial waste repository. United States could become the first economy in the world to have an operating deep-geologic commercial repository if it meets its goal of initiating repository operations by 2012.

The United States already has a purpose-built deep geological repository operating in New Mexico since 1999 for long-lived military radioactive wastes. It is the first and only underground repository licensed for the permanent disposal of long-lived radioactive waste in the world and it serves as proof that the technology for the deep burial of high level radioactive waste is available and has been put to use (see Chapter 5: Waste Management).

JAPAN

BACKGROUND

Japan is one of the largest economies in the world with a per capita income of US$ 23,828 (1995 US$ at PPP). Up to 1990 Japan had experienced rapid economic development but since the crash of the stock exchange market in 1992 it entered a long period of stagnation. GDP growth in 2001 was only 0.3 percent and unemployment reached 5 percent.[25] The economy gave signs of an imminent recovery when a 6.4 percent annualised growth rate was reported for the quarter of October-December 2003, the highest in 13 years. Strong exports to fast-growing China, boosting business investment and company profits, are likely to maintain growth albeit at a slower pace. Real GDP growth for the fiscal year 2003 was of 3 percent with respect to the previous year, and the Japanese Government is confident that growth for 2004 will be between 1.6 and 1.9 percent.[26]

Japan has scarce indigenous energy resources and in 2001 imported 80 percent of its primary energy supply, not considering uranium. If uranium imports are included (not the common practice in energy balance calculations), then imports amount to a full 92 percent of primary energy supply. Imports account for almost 100 percent of Japan's oil consumption, 99 percent of coal demand, 97 percent of gas use, and 100 percent of the uranium. Total primary energy supply in 2001 was 508 Mtoe. Per capita energy consumption in 2001 was 2.8 toe.[27]

Between 1980 and 1999, electricity demand in Japan has grown at an annual average rate of 3.03 percent.[28] Nuclear power generation in 2003 accounted for a 25 percent share of Japan's total generation [29], although that particular year could hardly be called typical for nuclear generation as a result of the forced shutdown of Tokyo Electric Power Company's (TEPCO) reactor fleet plus other reactors at Chubu and Tohoku Electric Companies. A more representative figure is around 34 percent, the average of the 3 years prior to 2002 when the first reactors were shutdown.[30] In 2001, generation by conventional fuels (coal, natural gas and fuel oil) made up around 60 percent of the total and generation by hydro resources accounted for close to 8 percent.[31]

CURRENT SITUATION OF NUCLEAR POWER

Japan has 10 vertically integrated private electric power companies, each one operating within its own regional franchise service area but generally trading power among themselves to ensure supply security and reliability. In addition to these there are 2 major wholesale power supply companies and a host of other small outfits all selling their generated power to the 10 independent electric companies. The two wholesale power suppliers are: Japan Atomic Power Company (JAPC) owned by 9 of the electric companies and with a small percentage ownership by the government; and J-Power (officially the Electric Power Development Co. Ltd.) which is in the process of privatisation and also owns transmission line segments of the Japanese electric grid. The small wholesale companies are mostly single hydropower plants owned by the different prefectures.

Japan does not have indigenous uranium resources, so it relies on imports. Since the beginning of the nuclear industry and up to the year 2000, Japan imported a cumulative total of 303,400 tonnes of uranium dioxide from Australia, Canada, China, France, Niger, United Kingdom, United States and South Africa.[32]

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25 EWG/APERC (2003).

26 Reuters (2004).

27 EWG/APERC (2003).

28 APERC (2002).

29 IAEA (2004a).

30 METI (2004).

31 EWG/APERC (2003).

32 MEXT (2001).

Table 6 Nuclear power data summary, Japan

Reactors in operation	53
Nuclear installed capacity (gross)	47,122 MW
Reactors under construction	2
Total electricity generation	919.9 TWh
Nuclear generation	230.1 TWh
Nuclear generation share	25 %

Note: Generation figures for 2003.
Source: JAIF (2004), IAEA (2004).

Ever since starting its nuclear research programme in 1954, Japan has progressively developed a domestic nuclear capability encompassing all aspects of the industry, from fuel procurement and reactor construction and design to the management of spent fuel and handling of wastes. By the end of the 1970s Japan had established its own domestic nuclear reactor production capacity, and is now involved in collaboration efforts with other economies for the development of new designs that have the potential to be used anywhere around the world.

Japan's first commercial reactor, Tokai 1, was a 160 MW Magnox gas-cooled type designed in the UK that began operation in 1966; it was retired in 1998 after 32 years in service. Subsequent reactors have been all of the light water-cooled kind, either boiling water reactors (BWR) designed by General Electric, or pressurised water reactors (PWR) designed by Westinghouse. Japanese companies Hitachi, Mitsubishi and Toshiba, through a process of joint construction and licensing of technology have advanced to the point of developing their own capability and becoming suppliers and construction contractors of complete nuclear steam supply systems (NSSS).[33]

Nine of the major electric companies and the Japan Atomic Power wholesale company own and operate reactors in Japan. J-Power, the other wholesale company, does not own a nuclear reactor at present but is planning the construction of its first advanced BWR type reactor to go online in 2012 at Ohma. In all, there are currently 53 operating reactors in Japan for a total gross capacity of 47,122 MW, with Hamaoka Unit 5 being the last to be connected to the grid in April 2004. Two reactors have been shutdown permanently after having ended their long useful lifetimes: the previously mentioned Tokai commercial unit after 32 years, and the Fugen prototype reactor after 24 years. All operating reactors use enriched uranium fuel and are of the light water type, almost equally divided between BWRs and PWRs. Japan is the first economy in the world to implement advanced reactors, also called 3rd generation reactors. Advanced BWR reactors have been used in Japan since 1996. Three are currently in operation, Units 6 and 7 at the Kashiwazaki Kariwa site connected to the grid in 1996 and the above mentioned Hamaoka Unit 5 having been connected recently in April 2004. There are two reactors under construction at the moment: a 1,300 MW advanced BWR at Shika (Unit 2), and a 1,100 MW BWR at Higashi Dori (Unit 1).

To help make the siting of nuclear installations more attractive, the Japanese government has had a programme to provide subsidies to the townships that are willing to host them.[34]

[33] The steam-producing section of a nuclear power plant comprised of the nuclear reactor, containment vessel, steam generators, primary cooling circuit and circulating water pumps. The system provides steam to the power-producing turbine and generator group section.

[34] IEA (1998).

Table 7 Nuclear power reactors in operation and under construction in Japan

Name	Type	Operator	Gross Capacity (MWe)	Date Connected
Operational				
Fukushima-Daiichi 1	BWR	Tokyo Electric	460	11/17/1970
Fukushima-Daiichi 2	BWR	Tokyo Electric	784	12/24/1973
Fukushima-Daiichi 3	BWR	Tokyo Electric	784	10/26/1974
Fukushima-Daiichi 4	BWR	Tokyo Electric	784	2/24/1978
Fukushima-Daiichi 5	BWR	Tokyo Electric	784	9/22/1977
Fukushima-Daiichi 6	BWR	Tokyo Electric	1,100	5/4/1979
Fukushima-Daini 1	BWR	Tokyo Electric	1,100	7/31/1981
Fukushima-Daini 2	BWR	Tokyo Electric	1,100	6/23/1983
Fukushima-Daini 3	BWR	Tokyo Electric	1,100	12/14/1984
Fukushima-Daini 4	BWR	Tokyo Electric	1,100	12/17/1986
Genkai 1	PWR	Kyushu Electric	559	2/14/1975
Genkai 2	PWR	Kyushu Electric	559	6/3/1980
Genkai 3	PWR	Kyushu Electric	1,180	6/15/1993
Genkai 4	PWR	Kyushu Electric	1,180	11/12/1996
Hamaoka 1	BWR	Chubu Electric	540	8/13/1974
Hamaoka 2	BWR	Chubu Electric	840	5/4/1978
Hamaoka 3	BWR	Chubu Electric	1,100	1/20/1987
Hamaoka 4	BWR	Chubu Electric	1,137	1/27/1993
Hamaoka 5	ABWR	Chubu Electric	1,380	4/30/2004
Ikata 1	PWR	Shikoku Electric	566	2/17/1977
Ikata 2	PWR	Shikoku Electric	566	8/19/1981
Ikata 3	PWR	Shikoku Electric	890	3/29/1994
Kashiwazaki Kariwa 1	BWR	Tokyo Electric	1,100	2/13/1985
Kashiwazaki Kariwa 2	BWR	Tokyo Electric	1,100	2/8/1990
Kashiwazaki Kariwa 3	BWR	Tokyo Electric	1,100	12/8/1992
Kashiwazaki Kariwa 4	BWR	Tokyo Electric	1,100	12/21/1993
Kashiwazaki Kariwa 5	BWR	Tokyo Electric	1,100	9/12/1989
Kashiwazaki Kariwa 6	ABWR	Tokyo Electric	1,356	1/29/1996
Kashiwazaki Kariwa 7	ABWR	Tokyo Electric	1,356	12/17/1996
Mihama 1	PWR	Kansai Electric	340	8/8/1970
Mihama 2	PWR	Kansai Electric	500	4/21/1972
Mihama 3	PWR	Kansai Electric	826	2/19/1976
Ohi 1	PWR	Kansai Electric	1,175	12/23/1977
Ohi 2	PWR	Kansai Electric	1,175	10/11/1978
Ohi 3	PWR	Kansai Electric	1,180	6/7/1991
Ohi 4	PWR	Kansai Electric	1,180	6/19/1992
Onagawa 1	BWR	Tohoku Electric	524	11/18/1983
Onagawa 2	BWR	Tohoku Electric	825	12/23/1994
Onagawa 3	BWR	Tohoku Electric	825	5/30/2001
Sendai 1	PWR	Kyushu Electric	890	9/16/1983
Sendai 2	PWR	Kyushu Electric	890	4/5/1985
Shika 1	BWR	Hokuriku Electric	540	1/12/1993
Shimane 1	BWR	Chugoku Electric	460	12/2/1973
Shimane 2	BWR	Chugoku Electric	820	7/11/1988
Takahama 1	PWR	Kansai Electric	826	3/27/1974
Takahama 2	PWR	Kansai Electric	826	1/17/1975
Takahama 3	PWR	Kansai Electric	870	5/9/1984
Takahama 4	PWR	Kansai Electric	870	11/1/1984

Tokai 2	BWR	Japan Atomic	1,100	3/13/1978
Tomari 1	PWR	Hokkaido Electric	579	12/6/1988
Tomari 2	PWR	Hokkaido Electric	579	8/27/1990
Tsuruga 1	BWR	Japan Atomic	357	11/16/1969
Tsuruga 2	PWR	Japan Atomic	1,160	6/19/1986
Under construction				
Higashi Dori 1	BWR	Tohoku Electric	1,100	2005
Shika 2	ABWR	Hokuriku Electric	1,358	2006

Source: JAIF (2004b) and METI (2004).

Japan is not entirely self-sufficient in all the stages of the nuclear fuel cycle. In some cases, as in fuel procurement, it is due in part to international market conditions that favour contracting the services elsewhere.

The Japan Nuclear Cycle Development Institute (JNC), is a government research and development organisation with the mission to develop the processes of the nuclear fuel cycle, and it has operated some fuel cycle facilities and offered services to the nuclear industry in Japan. Its activities now focus on fast breeder reactor development, reprocessing of high-burnup fuel, mixed uranium-plutonium oxide (MOX) fuel fabrication, and high-level waste disposal. JNC operates a small uranium refining and conversion plant and a centrifuge enrichment demonstration plant both at Ningyo Toge; an experimental mixed oxide (MOX) fuel facility for the Fugen test reactor and the fast breeder programme; and a 90 tonne/year reprocessing pilot plant that has treated over a thousand tonnes of spent fuel since 1977 at Tokai. In addition, it operates a spent fuel storage facility also in Tokai and has plans for another one.

Uranium enrichment services on a commercial basis are contracted to Japan Nuclear Fuel Ltd., to the United States Enrichment Corporation and to EURODIF, a European consortium formed by France, Belgium, Italy and Spain. Japan Nuclear Fuel Ltd. (JNFL), along with Nuclear Fuel Transport Co. Ltd., are enterprises now owned by the 10 utility companies that own nuclear reactors in Japan and by other Japanese concerns. Together these two companies offer a wide range of nuclear fuel services: uranium enrichment, disposal of low-level radioactive wastes, interim storage of high-level wastes, and the transportation of uranium, low-level wastes and spent and re-fabricated fuel. Reprocessing and MOX fuel fabrication will be added to the range of services available.

The nuclear fuel cycle complex at Rokkasho in Aomori prefecture is where most of JNFL's facilities are located, and include a large-scale uranium enrichment plant, a low-level waste disposal facility and a vitrified high-level waste interim management centre. A commercial reprocessing facility with a capacity of 800 tonnes of uranium/year is almost finished and undergoing tests and is expected to begin formal operations by 2006. Up until now, most reprocessing has been performed in reprocessing plants in Europe. Japanese companies have so far contracted the reprocessing of 7,100 tons of uranium from COGEMA in France and BNFL in the UK to recover approximately 30 tons of plutonium plus unburned uranium.[35] A MOX fabrication plant is also being planned for JNFL's fuel cycle complex.

The high-level waste interim storage facility in Rokkasho, the first in Japan, has been in operation since 1995.[36] Currently the vitrification of high-level wastes (mixing high level wastes with glass for solidification in stable crystalline form) is being done in Europe, but there are plans to construct a vitrification plant in the Rokkasho site, allowing for the coverage of all the waste processing activities domestically.[37]

All nuclear plants in Japan are required to individually provide interim storage facilities on-site for low-level radioactive waste. Afterwards, permanent disposal is carried out in landfill-type sites. The

35 FEPC (2004).

36 WNA (2003f).

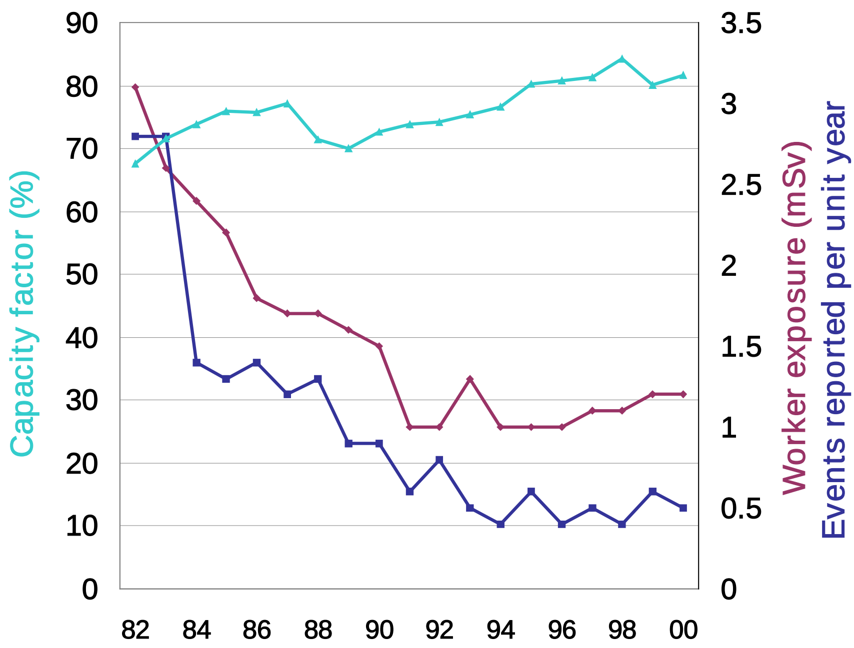
37 FEPC (2004).

low-level radioactive waste landfill in operation at JNFL's Rokkasho site, mentioned before, receives wastes from nuclear plants throughout Japan.

NUCLEAR POWER OPERATING COSTS IN JAPAN

In Japan, as in other economies in the world that have been using nuclear power since the beginnings of the industry, reactor performance parameters have tended to increase in the last few decades as the technology has become fully mature and in an effort to push prices of electricity down. Since 1982, the records have shown a tendency of improvement in relevant reactor performance parameters. Figure 12 shows how the average capacity factor for reactors in Japan has been improving since 1982, establishing itself firmly at over 80 percent by the year 2000. Other important parameters such as worker exposure and reported reactor events show improvement too. These parameters are a measure of the industry's attention to proper organisational procedures, workplace guidelines and effective worker training. In Japan in average, annual worker exposure to radiation has steadily decreased to below 1.5 mSv (mili Sievert) while reported unplanned events have reached a value of around one-half per reactor per year.

Figure 12 Reactor performance parameters in Japan, 1982-2000



Source: JAIF (2003).

These performance parameters and the high cost of alternative fuels in Japan make nuclear power plants the cheapest to operate in the nation. As much as 88 percent of oil in Japan is imported from the Middle East, which traditionally has had a higher price structure for shipments to the Northeast Asian region.[38] Natural gas is imported in the form of LNG from Indonesia, Malaysia and Australia and also carries high transportation costs. Furthermore, LNG contracts in Japan link its price to that of oil, which tends to push the price upwards. Steam coal for power generation in Japan is imported from places as faraway as Australia, Canada, China, Indonesia, Russia United States and South Africa. The impact of transportation costs on the overall price of coal in Japan amounts to as much as 50 percent.

[38] APERC (2003).

The comparative costs of power generation in Japan as determined in an analysis by the Ministry of Economy, Trade and Industry (METI) in December 1999 can be seen in Table 8, which shows that nuclear power has the lowest cost as compared to oil, LNG and even coal-fired plants.

Table 8 Electricity generation costs for different plant types in Japan, 1999 (US cents/kWh)

	Nuclear	Hydro	Oil	LNG	Coal
Overall generation costs US cts./kWh	5.5	12.7	9.5	6.0	6.1

Notes: Exchange rate: 107 Yen/US$.
Using 40 years plant lifetime and 80% capacity factor for nuclear plants.
Calculated at 1998 average fuel prices in Japan.
Source: METI.

Nuclear power generation costs as calculated by the METI are competitive even though as can be seen in Table 9 they include the costs attributable to reprocessing of spent fuel, handling of the resulting high level wastes and considering the funds put aside for decommissioning at the end of the plants' lifetime.

Table 9 Nuclear generation costs breakdown, Japan (US cents/kWh)

	US cents/kWh
Total nuclear generation costs	*5.5*
Capital and decommissioning	*2.1*
Capital costs	2.0
Decommissioning costs	0.1
Operation and maintenance	*1.8*
Fuel cycle costs	*1.6*
Fuel procurement	0.7
Reprocessing	0.6
Waste management	0.3

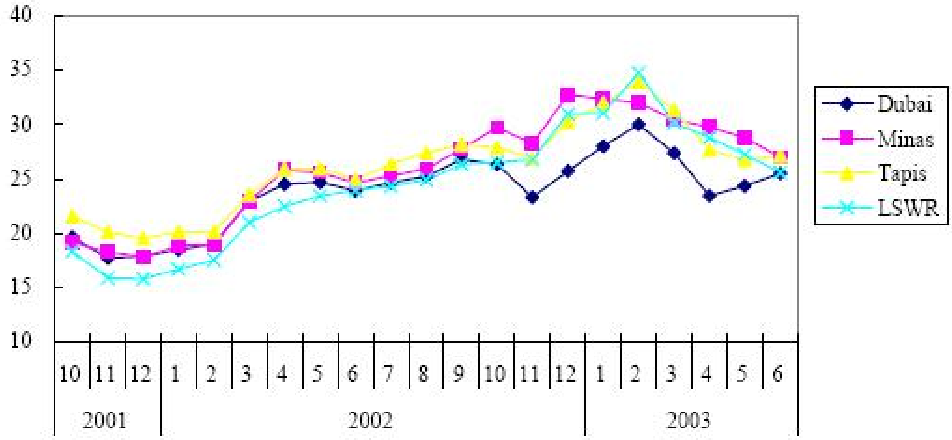
Note: Exchange rate: 107 Yen/US$.
Source: METI.

TEPCO REACTOR SHUTDOWNS

In 2002 the surfacing of falsified records in nuclear power plant inspections in at least two of TEPCO's nuclear plants generated a reaction by the atomic energy overseeing organisation and by the public that forced the shutdown of all of the company's 17 reactors for re-inspection. Afterwards, Chubu Electric Power Company and Tohoku Electric Power Company also announced the shutdown for re-inspection of reactors in which they had failed to report safety breaches. The fact that the reactor fleet at TEPCO represents 45 percent of the electricity generation in the Tokyo area raised doubts as to whether there would be enough power to deal with peak loads during the summer of 2003. By July 2003, TEPCO was 4.4 thousand MW short to meet the 64.5 thousand MW expected summer demand. It did not materialise, however, due to an abnormally cool summer that year. By the time the summer demand loads of 2004 started to pick up, all of the TEPCO plants except for two had already been restarted.

Impacts of this incident included a downturn in TEPCO's net profit in the first half of 2003 of 44% as compared to the previous year. Reasons cited for this were higher cost of fuels required to replace lost nuclear generation, refurbishing work required in the reactors, low revenues during the cool summer and the result of an energy savings campaign that was instituted to avoid power shortages. TEPCO announced that heavy reliance on thermal plants caused a 45% increase in fuel costs during a 6 month period and that the total cost of the shutdown during the one year period was 290 Billion yen.[39] At the same time the estimated increase in CO_2 emissions due to the use of alternative fuels was 42 Million tonnes of CO_2 in 1 year. This figure represents a 3.4 percent increase over Japan's 1990 total emissions of 1,235 million tonnes of CO_2. This is significant when considering that a 6 percent reduction from such level is required to meet the Kyoto Protocol commitments.[40]

Figure 13 Development of prices of crude oil and fuel oil for power generation



Notes:

Prices in the spot markets of crude oil types typically used for power generation.

Prices are for the Singapore market.

Minas corresponds to Sumatra Light.

Tapis is the average of low sulphur and light Tapis.

LSWR (low sulphur waxy residue) corresponds to low sulphur fuel oil cracked.

Source: IEEJ (2003).

Asian fuel markets were also impacted by the event. A study by the Institute of Energy Economics, Japan [41] indicated that combined consumption of crude oil and fuel oil in Japan in 2003 increased 442 percent compared to the previous year, and the prices of crude oil and natural gas for the area saw large increases as a result. As can be witnessed in Figure 13, spot market prices of crude oil types typically used for power generation in Southeast Asia show large gaps in price with respect to the spot price of Dubai crude in the Middle East market beginning in the 4th quarter of 2002 and continuing through the 1st quarter of 2003, the period when the Japanese nuclear plants were shut down. According to the study, the increase in the price of Minas also had an influence on the Daqing, on Vietnamese crudes imported to Japan, and on the low sulphur waxy residue (LSWR) price in the Singaporean market. Similar effects extended to the prices of LNG in the region as these are indexed to the prices of oil. The study is careful to remark that other events during the same period caused oil supply disruptions and might have also had an impact on the markets, such as: the halt of exports from Iraq, the strike of oil workers in Venezuela, and the ethnic conflicts in Nigeria.

[39] The Japan Times (2003).

[40] AEC (2003).

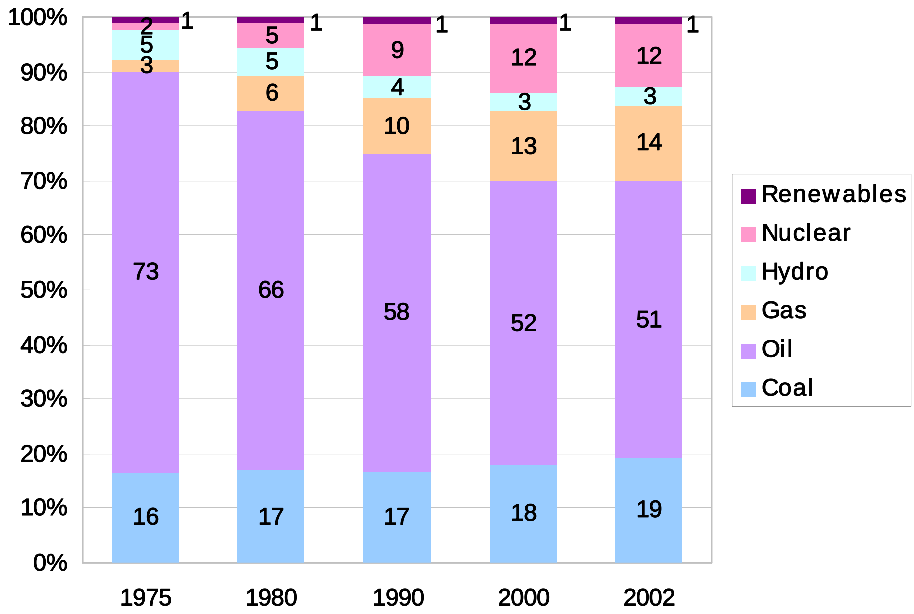
[41] IEEJ (2003a).

JAPAN'S NUCLEAR POWER POLICY

Japan's heavy use of nuclear power comes as the result of a strategic need to reduce its dependence on oil, gas and coal imports. Nuclear power represents an important part of Japan's primary energy supply, at around 12 percent today, owing to nuclear energy's comparably more reliable fuel supply together with its potential to help reduce emissions to the environment.

Nuclear power is seen as the most economically feasible energy resource to achieve the goals set by the Basic Law on Energy Policy, which took effect in June 2002. The Basic Law emphasises ensuring a stable supply of energy and includes as priorities the protection of the environment and the improvement of energy efficiency. The Basic Energy Plan that derives from the Basic Law states that nuclear power generation, together with fuel reprocessing, should be promoted as a key source of electricity with the basic premise that safety should be ensured. The Long Term Program for Research, Development and Utilization of Nuclear Energy establishes the government of Japan's nuclear policy and explains nuclear energy's role in the overall energy policy set forth in the Basic Law and the Basic Energy Plan. The Long Term Program was first published by the Atomic Energy Commission in 1956 and is revised every 5 years. The latest version is dated November 2000 and it commends nuclear power as a wise and rational policy for the government of Japan and advises keeping it as a mainstay of the nation's energy supply while maintaining its share in the power generation mix at an appropriate level. Since 1985 and up to 2002, except for a couple of years, nuclear power has been the largest contributor to electricity generation in the nation, averaging a 34 percent share between 1999 and 2001.[42] Nuclear power plays a major role in Japan's present energy landscape and this condition is expected to continue into the mid term future. The Long-Term Program remarks that Japan is among the economically and industrially advanced nations with the highest rate of primary energy dependence on oil and an alarmingly high rate of reliance on Middle Eastern oil imports, and therefore an important strategy for Japan should involve the use of alternative energy sources to the extent feasible.

Figure 14 Evolution of Primary Energy Supply structure in Japan, 1975-2002 (Percentage)



Source: EDMC (2004).

[42] TEPCO (2003).

Japan's primary energy supply structure nowadays reflects the prominence of fossil fuels, most of which are imported, and of oil in particular. As noted earlier, 100 percent of the oil, 99 percent of the coal and 97 percent of the natural gas consumed in Japan are imported; and as shown in Figure 14, these fossil fuels added together made up 84 percent of the primary energy structure in 2002. Fuel diversification policies have reduced the magnitude of oil's participation since 1975 when it peaked at 73 percent. However in 2002 it still represented a share of 51 percent, in large part required by the heavy use of this fuel in the transportation sector. Nuclear power and imported LNG are the fuels with which oil's share has been gradually replaced.

For an economy like Japan it is preferable to rely on foreign nations for uranium than for conventional fuels. Uranium is more readily obtainable from a large number of countries, many of them OECD members, which are seen in Japan as more stable and with interests and agendas more compatible to its own than those of Middle Eastern nations. Uranium also has a history of stable supply with low volatility in prices as compared to oil and natural gas. Japan's widely accepted figure for import dependency of 80 percent is calculated assuming uranium as an indigenous energy source, an assumption generally made by many organisations in the formulation of energy balance tables, including APERC. In reality Japan's self-sufficiency rate in 2001 was only of around 7 percent if uranium is counted an import, which in reality it is. It is thanks to the use of uranium (even though it is not an indigenous energy source) for the generation of 25 percent or more of the electricity consumed in Japan that this economy can claim that its overall energy self-sufficiency is as high as 20 percent.

Japan is committed to reprocessing and to the use of MOX fuel for its nuclear fuel cycle. Reprocessing is the dismantling of spent fuel for the chemical recovery of unused uranium and plutonium and its re-utilisation in new fuel. MOX is the name given to fresh fuel fabricated from a mixture of uranium and plutonium oxides and can be used in conventional reactors as well as in fast breeder reactors (reactors that breed more fuel material than they consume). The term *pluthermal* is used in Japan to describe just such a strategy owing to the use of plutonium in conventional light water reactors of the low energy or *thermal* energy range type, as opposed to breeder reactors operating in the high energy or *fast* energy range. METI endorses reprocessing as essential for Japan to maintain stable supplies of electricity given its scant indigenous resources. The *Basic Energy Plan* states that the use of MOX fuel in thermal (light water) reactors should be promoted steadily as the central part of the domestic nuclear fuel cycle.

In 1997 a decision by the Atomic Energy Commission with the approval of the Cabinet resulted in a joint plan by Japan's power companies to use reprocessed fuel in a total of between 16 and 18 reactors by the year 2010. Under this plan, 5 to 8 tonnes of plutonium will be consumed annually in MOX fuel form in the mentioned 16 to 18 reactors across the nation, and JNFL's reprocessing plant in Rokkasho would begin operations in 2006 providing 5 tonnes of the total plutonium required annually.[43] The programme however, fell behind schedule due to problems with data falsification of MOX fuel originated in the UK and the TEPCO shutdowns.

There does not seem to be any intention of backing away from the plan, though. To date, fuels fabricated from the mix of recovered plutonium and uranium oxides (MOX) have been utilised on a trial basis at Japan Atomic Power Company's Tsuruga No. 1 unit and at Kansai Electric Power Co.'s Mihama No. 1 unit, and plans are progressing for more extensive use of these fuels.[44] In December 2003 the Presidents of the Electric Utilities in Japan announced a joint re-confirmation to continue with the plan to use MOX fuel and reported the individual progress achieved by each utility. Kansai Electric Power Co. Inc., among them, is finalising a contract for overseas MOX fuel fabrication in order to get its MOX plans back on track. Later in 2004, the same group announced their unanimous decision to cooperate among themselves to put into operation the JNFL reprocessing plant at Rokkasho.[45]

[43] FEPC (2004).

[44] ANRE (2003).

[45] FEPC (2004).

More recently, articles in the local press fuelled the controversy in the House of Representatives regarding the nation's recycling policy. Sparked in part by the proximity of final testing before commercial operation at the reprocessing plant under construction at Rokkasho, articles accused Governmental bodies of hiding fuel reprocessing costs that were costlier than direct disposal of spent fuel in order to obtain approval for the *Long Term Program for Research, Development and Utilisation of Nuclear Energy* that proposes the recycling policy. However it is a well established fact in the international nuclear industry that reprocessing is on the average (and depending on each specific case) around 3 percent more expensive than direct disposal in terms of overall lifetime generation costs.[46] In Japan as in other nations, the decision to reprocess spent nuclear fuel is not one based solely on economics, but also on energy security and the price that a nation places on the reliability of its future energy supply.

One of the advantages or side effects of a *pluthermal* or reprocessing fuel cycle is the reduction in the volume of high level wastes produced. Whereas in a direct disposal scheme entire fuel assemblies are discarded including its 97 percent of reusable uranium and plutonium plus its metallic structural components, in reprocessing the fuel is stripped of its structural gear and then chemically processed to extract the sought after materials and separate the highly toxic parts. At the end the high-level radioactive wastes are obtained in liquid form and reduced to only 3 percent of the original spent fuel assembly.

At present the government plan for the management of these wastes involves vitrifying the liquid high-level radioactive wastes (mixing the wastes with glass for solidification in crystal form), a 30 to 50 year temporary cool-down storage period, and final deep underground geological burial in stable bedrock. The *Law on Final Disposal of Specified Radioactive Waste* of 2000 mandates deep geological burial for final disposal of high-level wastes. It also provided for the formation of the *Nuclear Waste Management Organisation* (NUMO), a private organisation formed in 2000 to formulate plans for disposal, select sites, research and demonstrate technologies, and construct and operate a repository.[47] NUMO's plans for the construction of a final repository are to select areas for detailed investigation between 2008 and 2012; final selection of a site for repository construction between 2023 and 2027; and start of operations between 2033 and 2037.[48]

Final disposal for low-level radioactive wastes after interim storage at each facility is already being provided at the Rokkasho low-level disposal centre.

NUCLEAR POWER CONTRIBUTION TO SUSTAINABLE DEVELOPMENT

With the Kyoto Protocol now set to become effective sometime in 2005, Japan faces a legal binding on reducing its emissions of greenhouse gases by 2008-2012 to a level 6 percent below the one it held in 1990. Japan considers nuclear power an important part of its strategy to cope with these requirements.

Figure 15 is a graphic depiction of nuclear power's contribution to the reduction of CO_2 emissions from power generation in Japan. Since 1975 CO_2 emissions have not grown at the same rate as power consumed as a direct result of the increase of the share of nuclear power in generation. The specific CO_2 emissions in kg per kWh show a descending trend mirroring nuclear power's increase.

The government of Japan's planned actions to meet its commitments of CO_2 emissions reductions as per the Kyoto Protocol are described in its document *Guidelines for Measures to Prevent Global Warming*. Now that the Kyoto Protocol is a certainty there will likely be changes in environmental policy, however until revisions are made the policy of the government of Japan to prevent global warming continues to be that contained in this document. Japan's intended strategy is to reduce energy-related CO_2 emissions by the year 2010 (including those from power generation) to the same level they had in 1990, and to establish additional measures in other sectors to achieve the

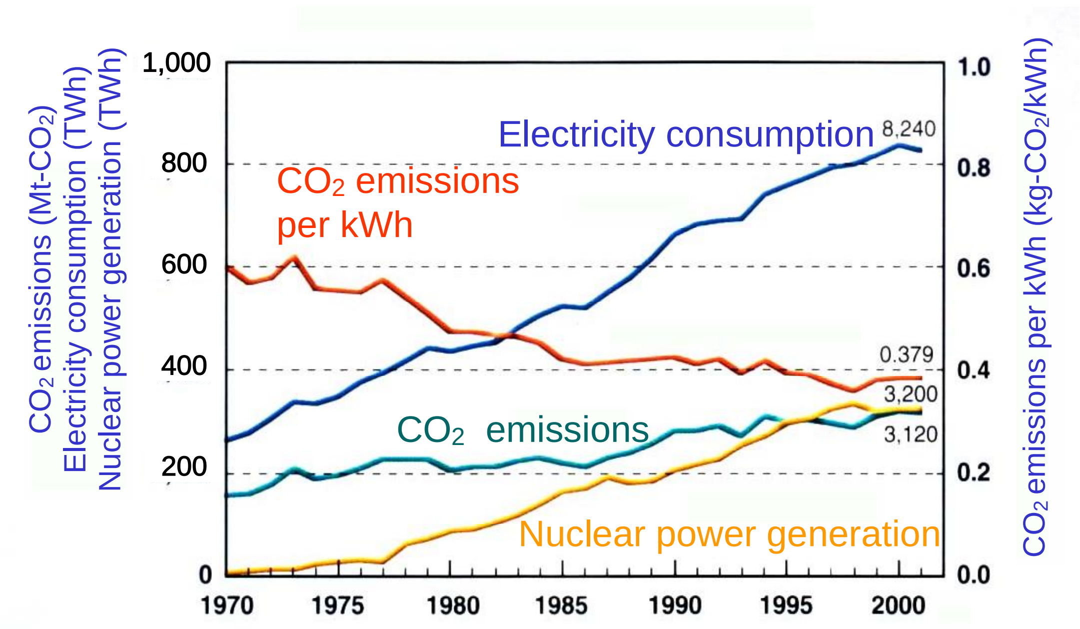
[46] NEA (1994).

[47] WNA (2003f).

[48] NUMO (2004).

reductions needed to meet the minus 6 percent (6 percent under the 1990 level) target. Included in the specific actions for the energy-related part of the emissions is the construction of an additional 30 percent of the nuclear capacity existing in the year 2000. This would amount to around 12,000 additional megawatts, or somewhere between 10 and 13 new nuclear units by the year 2010. The specific actions also feature aid grants for the social and economic development of local areas hosting nuclear facilities.

Figure 15 Nuclear power contribution to CO_2 emission reductions in Japan



Source: JAIF (2003).

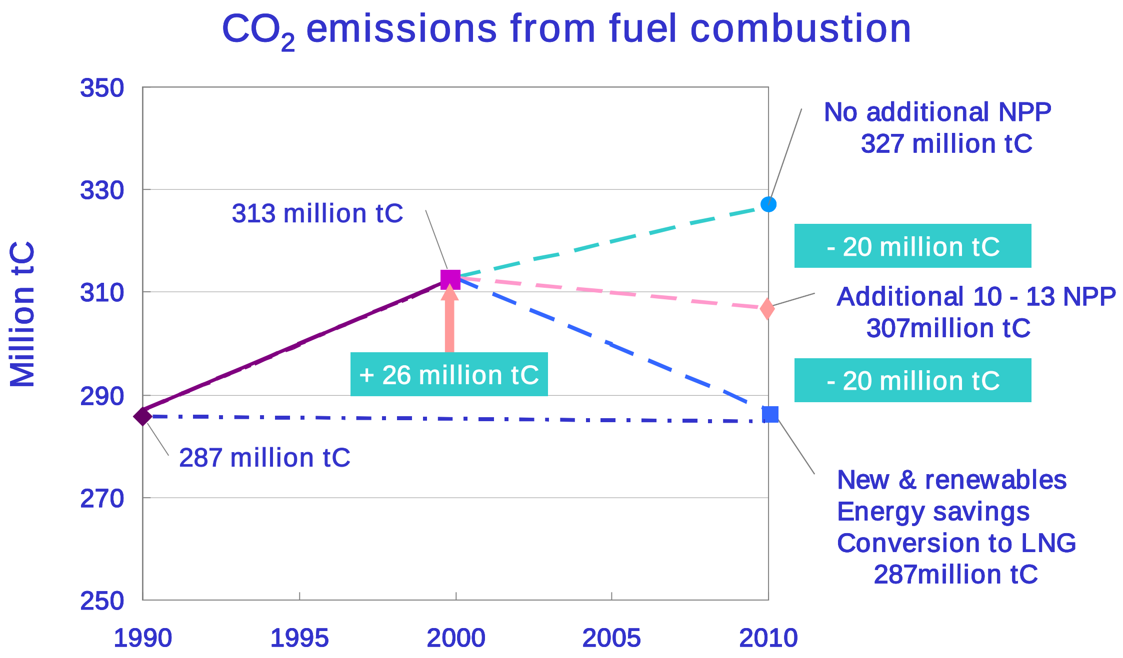
Figure 16 summarises the Guidelines actions directed specifically at reducing energy-related emissions and shows the relative participation of nuclear power. CO_2 emissions from fossil fuel combustion reached 313 million tonnes of carbon (tC) by the year 2000. Fulfilling future electricity demand with conventional fossil fuel power plants would yield a level of carbon emissions of 327 million tC by 2010 (light blue line on top). Adding anywhere from 10 to 13 nuclear power plants, would render an emissions level of 307 million tC (pink line in the middle). To reduce emissions in the energy sector further and reach a level of 287 million tC similar to that in 1990 requires additionally: a) implementing new and renewable energy technologies, b) instituting power savings policies in all sectors of the economy, and c) establishing a programme to convert existing power plants fuelled by other fossil fuels to natural gas.

PUBLIC OPINION ISSUES

Plans to construct more nuclear plants can be seriously impaired by a number of events that have greatly increased the public's mistrust in nuclear energy. The almost new Monju fast breeder prototype reactor had just achieved criticality and was undergoing tests at low power in 1995 when liquid sodium leaked from a pipe in the non-radioactive turbine-generator (or secondary) cooling circuit, causing a fire. Questions surrounding cover-ups during the investigation of the incident led to the cancellation of the operating license by the High Court in Nagoya in 2002, and the issue is still under discussion at the national Supreme Court level. The delays and the possibility of the facility's definitive cancellation could mean an important setback to Japan's fast breeder development programme.

In 1997 a fire at a radioactive waste treatment facility at the experimental reprocessing plant at Tokai liberated a small quantity of radioactive material into the atmosphere. In 1999 it was uncovered that a batch of reprocessed MOX fuel produced in the United Kingdom had falsified quality records and had to be returned to its manufacturer in 2002 after a long period of negotiations and much publicity. In the same year, a nuclear chain-reaction (criticality) accident irradiated and killed two workers in a fuel processing facility in Tokaimura. The small plant operated no more than 2 months per year and was used mainly to produce short batches of fuel for the fast experimental reactor at Joyo. The accident was traced back to the improper use and violation of established work procedures by the workers.

Figure 16 CO_2 emission reductions possibilities in the energy sector in Japan (Million tonnes of carbon)



Source: JAIF (2003).

In 2002 the falsification of inspection records at TEPCO was discovered, and just in August of 2004 the rupture of a pressurised hot water pipe in the non-radioactive turbine-generator (secondary) cooling loop at Kansai Electric's Mihama number 3 reactor in Fukui Prefecture caused the death of 4 workers. This was similar to an accident at the Surry nuclear power plant in Virginia, in the United States, where 4 people died when a boiling water and steam pipe burst there in 1986. Although the accident did not have any radiological consequences, and preliminary investigations are pointing to the fact that the inspection of this particular pressurised water line was not required by current mandatory procedures, it will in all likelihood have a negative effect on an increasingly sceptic public in Japan.

Now the government of Japan is faced with the dilemma of having nuclear energy as one of its few available options for countering fuel imports, and at the same time a crisis of public trust in its hands. Both the government and the nuclear industry in Japan recognise the need to regain the people's confidence as the only path towards formulating a nuclear power policy for the future. The Atomic Energy Commission of Japan in its White Paper on Nuclear Energy 2003 comments on the passage of new laws on nuclear safety and other reforms that will help prevent future accidents and avoid laxness or negligence in testing and inspections at nuclear installations. It also announces extensive public hearing activities, such as 'conferences for public participation and decision making in nuclear energy policy', to collect people's opinions and use it as a starting point towards a dialogue and a search for mutual understanding.

FUTURE PLANS

METI's Long-Term Energy Outlook recently published in June 2004 foresees the need to construct 4 new reactors by 2010 and a total of 10 new units by the year 2030. The Outlook projects also that nuclear energy will account for 15 percent of primary energy supply in Japan by the year 2030, up from about 12 percent today. The projection is based on the 10-year investment and construction plans of the 10 regional electric power companies and the 2 major wholesale power supply companies submitted every year by law to the METI, which estimate an electricity demand growth rate for the period 2003-2012 of 1.1 percent per year, itself lower than the estimate of the year before at 1.3 percent.

This represents a downward adjustment from the previous Outlook by METI in 2001, which envisioned between 10 and 13 new reactor units by 2010 and which formed the basis of its strategy against GHG emissions as established in the *Guidelines for Measures to Prevent Global Warming*. The reduced number of units according to the new Outlook is in response to the revised electricity demand growth rate, expected to be lower in the next 10 years and likely to taper off after peaking in 2021; and to an anticipated increased difficulty in gaining consent from local residents for the construction of new nuclear facilities.

Key to the overall plan against global warming, as set in the *Guidelines*, was to have zero new CO_2 emissions from energy production relative to 1990 levels; and this was to be accomplished with the inclusion of 10 to 13 nuclear plants before 2010 thereby increasing nuclear energy's share in power production to around 41 to 42 percent of the total. With the reduction in planned reactors such share will not be attained by 2010. METI in the current Outlook states that the volume of total GHG emissions from all sectors is expected to be over the target for 2010.

Table 10 lists the reactors planned or on order as of present. The first two units listed are scheduled to go into operation by 2010. These two units added to the two units under construction mentioned before, Higashi Dori 1 and Shika 2, represent the 4 new units to be operational by 2010 referred to in METI's new Outlook. The Fukushima 8 and Shimane 3 units, originally proposed for 2010, have delayed their plans and are now expected to be operational by 2011. The total number of reactors planned by the major electric power companies of Japan at the moment is 12.

Table 10 Nuclear reactors planned or on order in Japan

Name	Type	Operator	Gross Capacity (MWe)	Connected
Tomari 3	PWR	Hokkaido Electric	912	2009
Fukushima 7	ABWR	Tokyo Electric	1,325	2010
Fukushima 8	ABWR	Tokyo Electric	1,325	2011
Shimane 3	ABWR	Chugoku Electric	1,375	2011
Ohma	ABWR	J-Power	1,383	2012
Maki 1	BWR	Tohoku Electric	825	2012
Higashi Dori 2	ABWR	Tokyo Electric	1,385	After 2012
Kaminoseki 1	ABWR	Chugoku Electric	1,373	2012
Kaminoseki 2	ABWR	Chugoku Electric	1,373	2015
Tsuruga 3	APWR	Japan Atomic	1,500	2013
Tsuruga 4	APWR	Japan Atomic	1,500	2014
Namie Kodaka	BWR	Tohoku Electric	825	2014

Sources: METI (2004), FEPC (2004), WNA (2004), and CNA (2004b).

Included in the list is J-Power's first planned 1,383 MW nuclear reactor. The unit will be operational by 2012 in Ohma and will be an advanced BWR type plant with the flexibility to use either enriched uranium fuel alone or MOX fuel alone. Plans are for this unit to initially start with 1/3 of its fuel consisting of MOX fuel assemblies, and gradually thereafter raising the proportion of MOX elements.

Tsuruga units 3 and 4 have already obtained siting approval in March of 2004 by the Fukui Prefecture. The Japan Atomic Power Company's two new units will be of the advanced PWR type and are expected to be in service in 2013 and 2014.[49]

RESEARCH AND DEVELOPMENT

Japan has been active in joint schemes for continuing reactor development. It is the first nation to have constructed and operated advanced BWR type reactors. The two units at the Kashiwasaki Kariwa plant were constructed by a consortium of General Electric, Toshiba and Hitachi and have been in operation since 1996. A further advanced unit at Hamaoka was recently connected to the grid in April 2004 and is undergoing low power tests. Mitsubishi Heavy Industries and Westinghouse, together with the participation of four utilities are involved in the development of an advanced PWR reactor that will be used for Tsuruga units 3 and 4 about to start construction. The design will be the basis for the next generation of Japanese PWRs. Mitsubishi Heavy Industries is also participating in the development of Westinghouse's AP-1000 advanced reactor.[50]

In Fugen, a 165 MW Advanced Thermal Reactor (ATR) was built in the 1970s to test the use of mixed uranium and plutonium-oxide (MOX) fuel in a thermal (low-energy) reactor. The reactor was moderated by heavy water and cooled by light water and after operating for 24 years it was finally shutdown in March 2003. It was the world's largest consumer of MOX fuel rods with 772, or 20 percent of all MOX rods ever produced around the world. It provided plenty of information on the use of MOX fuels and was seen as a bridge to fast breeder reactors.

An experimental 140 MWt fast breeder reactor (FBR) (a high energy –or fast- reactor that produces more fuel material than it consumes) has operated successfully in Joyo since achieving first criticality in 1977. Another fast breeder reactor, but of the liquid metal cooled type (LMFBR), is the 280 MWe unit in Monju mentioned before that has been stopped since it experienced a sodium leak in 1995. However negative this incident's impacts on the fast breeder programme in Japan, a Feasibility Study on Commercialized Fast Reactor Systems is ongoing to define a plan for the research, development and commercialisation of liquid metal cooled fast breeder technologies.[51]

Japan is active in international joint development programmes such as the Generation IV International Forum (GIF) led by the United States and the IAEA's International Project on Innovative Nuclear Reactors and Fuel Cycles (INPRO), as well as a wide range of different research and development programmes being performed by academic institutions, private industry and government agencies supported and promoted by the Ministry of Education, Culture, Sports, Science and Technology and the Ministry of Economy , Trade and Industry.[52]

One notable such activity is that being performed under the Innovative and Viable Nuclear Energy Technology Program (IVNET).[53] This programme has provided US$ 7 Million in funds in 2000, US$ 12 Million in 2001 and US$ 19 Million in 2002 for studying more than 16 reactor concepts and for 5 feasibility studies. Under this research initiative designs must be economical, safe, have sustainability, offer non-proliferation advantages and be flexible in application to non-power uses. Some of the most promising concepts being studied under the initiative include:

- 300 MW resource renewable BWR with low moderation core and hybrid safety system. It has the possibility achieving commercial operation by 2030.

[49] CNA (2004b).
[50] WNA (2003f).
[51] IAEA (2003).
[52] AEC (2003).
[53] ANS (2002).

- 600 MW supercritical pressurised water cooled reactor with closed compact system, high efficiency, adaptability of thermal power technologies but also compatible with fast reactor cores. Probable deployment by 2020.
- 50 MW super safe simple sodium cooled fast reactor with inherent safety. Date not determined.

The International Thermonuclear Experimental Reactor (ITER) project is another international joint project with the purpose of demonstrating the feasibility of the nuclear fusion energy concept (as opposed to nuclear fission energy used currently in commercial atomic reactors). The four main participants in the international project are Canada, the European Union, Japan and Russia. Japan has been arguing for a more active participation in the project with the other international project members and negotiations are ongoing regarding where to site the proposed reactor.[54]

[54] AEC (2003).

RUSSIA

BACKGROUND

Russia's economy began growing again at the beginning of 1999 after a decade of contraction that reduced total GDP to 40 percent of the level it held in 1990. Boosted by higher oil prices and the stimulating effect of the ruble devaluation, the economy showed positive growth rates of 7.3 percent in 2000 and 5 percent in 2001. GDP per capita in 2001 amounted to US$ 6,575 (1995 US$ at PPP).[55]

Russia has abundant natural energy resources, possessing 32.1 percent of the world's proven reserves of natural gas (the world's largest), 4.6 percent of the world's proven oil reserves, and 15.9 percent of the world's coal reserves. The economic potential of hydropower is estimated at 852 TWh per year, of which almost 20 percent has been developed. Russia also owns 14 percent of the world's economic reserves of uranium. Energy is an influential factor in Russia's economic development. In 2001 the energy industry accounted for 13 percent of GDP and energy exports including oil and gas represented 40 percent of the economy's total exports. In the same year Russia exported around 65 percent of its total production of crude oil and 45 percent of its total production of natural gas. Total primary energy supply in 2001 was 611 Mtoe and per capita energy consumption was 3.1 toe.[56]

As a result of Russia's contracting economy, electricity demand had a decreasing trend for the most part of the 1990's. With a return to economic growth though, electricity generation might experience significant growth rates in the short to mid term future. Already total power generation in Russia has increased at a rate of 1.4 percent in 2000 and of 3.7 percent in 2001.[57] Power generation by nuclear means in 2003 accounted for 16.5 percent of the total.[58] The other most important sources of power generation in Russia are conventional thermal plants, which account for 65 percent of total generation, and hydropower accounting for 17 percent.[59]

CURRENT SITUATION OF NUCLEAR POWER

In 2004 the civil side of the Russian Ministry of Atomic Energy (MinAtom), and until then responsible for all atomic power policy in Russia, became the Federal Atomic Energy Agency (known also as Rosatom) and placed under the Ministry for Industry and Energy. Subordinate to Rosatom is Rosenergoatom, the state heat and electricity generation company that was created in 1992 to consolidate all civil nuclear utilities including those under construction at the time. In addition to that, Rosatom also includes the following entities:

- Nuclear Fuel Cycle Department
- TVEL, in charge of the production of nuclear fuel
- Techsnabexport (Tenex), in charge of foreign trade of nuclear fuel
- Atomstroyexport, in charge of foreign trade of equipment.

After the Chernobyl accident in 1986 an independent nuclear safety body was established which after two transformations finally became in 2004 the Federal Atomic Supervisory Service. This organisation establishes safety regulation and is responsible for licensing, inspection, operational safety of facilities and control of nuclear material.

The nuclear industry in Russia is set against an electricity system that is facing major challenges in its quest for modernisation and efficiency at a time when demand is expected to begin a healthy growth in the immediate future. The electricity system is burdened by obsolete and highly depreciated generation, transmission and distribution facilities and by difficulty in obtaining funds for investment

[55] EWG/APERC (2003).
[56] EWG/APERC (2003).
[57] EDMC (2004).
[58] IAEA (2004a).
[59] IEP (2003).

in new installations and for refurbishing and maintenance. Obsolete and under-maintained generation plants operate at low thermal efficiencies. Most of the natural gas-fired capacity in existence is of the low efficiency conventional type as opposed to the combined cycle systems now being favoured in new installations worldwide. There is also the impression that the fuel mix structure is not optimal and has an unjustified high reliance on natural gas. Furthermore, there are major limitations in transmission capacity that preclude the effective use of the installed generating capacity.

Table 11 Nuclear power data summary, Russia

Reactors in operation	30
Nuclear installed capacity (gross)	22,242 MW
Reactors under construction	5
Total electricity generation	836.9 TWh
Nuclear generation	138.4 TWh
Nuclear generation share	16.5 %

Note: Generation figures for 2003.
Sources: Rosatomenergo (2004), IAEA (2004).

Access to investment funds might continue to be limited for the immediate future given the perception of high risk in investment on power generation projects. For investors, new nuclear projects face the uncertainty of having acceptable capital costs or overall economical viability. Coal-plants face concerns over future restrictions to air polluting emissions, over whether enough production capacity is developed to ensure coal supply and over the economical transportation of coal from far-away distances. There is also uncertainty over the ability of the electricity transmission network to grow according to projected needs and efficiently handle increased electricity flows. A high perceived risk for investment projects means that there will remain to be financing difficulties for the electricity sector, delaying the time it will take to gradually modernise the system and increase installed capacity to meet the expected demand growth.

Figure 17 Location of nuclear power plants in Russia

Source: Rosenergoatom.

Table 12 Nuclear power reactors constructed and under construction in Russia

Name	Location	Type	Gross Capacity (MWe)	Date Connected
1st Generation plants				
Shut down				
Beloyarsky-1	Sverdlovsk	RBMK	108	4/26/1964
Beloyarsky-2	Sverdlovsk	RBMK	160	12/29/1967
Novovoronezh-1	Voronezh	VVER	210	9/30/1964
Novovoronezh-2	Voronezh	VVER	365	12/27/1969
Operational				
Novovoronezh-3	Voronezh	VVER	417	12/27/1971
Novovoronezh-4	Voronezh	VVER	417	12/28/1972
Kola-1	Murmansk	VVER	440	6/29/1973
Kola-2	Murmansk	VVER	440	12/9/1974
Leningrad-1	St. Petersburg	RBMK	1,000	12/21/1973
Leningrad-2	St. Petersburg	RBMK	1,000	7/11/1975
Bilibino Unit A	Far East	EGP 6	12	1/12/1974
Bilibino Unit B	Far East	EGP 6	12	12/30/1974
Bilibino Unit C	Far East	EGP 6	12	12/22/1975
Bilibino Unit D	Far East	EGP 6	12	12/27/1976
Kursk-1	Kursk	RBMK	1,000	12/19/1976
Kursk-2	Kursk	RBMK	1,000	1/28/1979
2nd Generation plants				
Operational				
Beloyarsky-3 (BN-600)	Sverdlovsk	FBR	600	4/8/1980
Novovoronezh-5	Voronezh	VVER	1,000	5/31/1980
Leningrad-3	St. Petersburg	RBMK	1,000	12/7/1979
Leningrad-4	St. Petersburg	RBMK	1,000	2/9/1981
Kola-3	Murmansk	VVER	440	3/24/1981
Kola-4	Murmansk	VVER	440	10/11/1984
Smolensk-1	Smolensk	RBMK	1,000	12/9/1982
Smolensk-2	Smolensk	RBMK	1,000	5/31/1985
Smolensk-3	Smolensk	RBMK	1,000	1/17/1990
Kursk-3	Kursk	RBMK	1,000	10/17/1983
Kursk-4	Kursk	RBMK	1,000	12/2/1985
Kalinin-1	Kalinin	VVER	1,000	5/9/1984
Kalinin-2	Kalinin	VVER	1,000	12/3/1986
Balakovo-1	Saratov	VVER	1,000	12/28/1985
Balakovo-2	Saratov	VVER	1,000	10/8/1987
Balakovo-3	Saratov	VVER	1,000	12/25/1988
3rd Generation plants				
Operational				
Balakovo-4	Saratov	VVER	1,000	4/11/1993
Rostov-1	Rostov	VVER	1,000	3/30/2001
Under construction				
Kalinin-3	Kalinin	VVER	1,000	2004
Rostov-2	Rostov	VVER	1,000	2005
Balakovo-5	Saratov	VVER	1,000	2006
Balakovo-6	Saratov	VVER	1,000	2011
Beloyarsky-4 (BN-800)	Sverdlovsk	FBR	800	2010
Construction halted				
Kursk-5	Kursk	RBMK	1,000	2005

Sources: IAEA (2004a), IEA (2002).

The history of the nuclear industry in Russia began with early attempts at atomic research before the Second World War. Research efforts briefly interrupted during the war were restarted with renewed interest immediately afterwards and led to the construction of Russia's first reactor for the production of nuclear material in 1948 and the test of its first atomic bomb in 1949. The civil nuclear industry was later based on Russian-developed military nuclear reactor designs much as it was in the United States. Civil reactors in Russia are derived from the weapons-plutonium production reactors and the reactors developed for the propulsion of navy ships.

The 70s and 80s saw an impressive rate of construction of civil reactors in Russia, with 13 of the operating reactors in the current fleet having been connected to the system during the 1970s and 14 of them during the 1980s. Today, Russia has 30 reactors in operation totalling a gross capacity of 22,242 MW. Performance parameters in Russian nuclear power plants have improved in the last few years, with the capacity factor (or the percentage of time a plant produces power in a year) increasing from 56 percent to 75 percent between 1998 and 2000. As a result electricity output at nuclear power plants reached a level of 138 TWh in 2003. Table 12 shows the details of all the reactors that have been constructed and that are under construction in Russia.

The oldest 4 civil reactors in Russia have been already shutdown. A total of 18 reactors that started construction in the 1980s were not finished due mainly to monetary constraints and low electricity demand. The government plans to restart work on some of these plants sometime in the future; but as of today, funds have been committed to restart construction only on the 6 plants shown in Table 12. The construction of Kursk-5 has been halted once again with the possibility of the project being aborted altogether.

Russia is completely self reliant in fuel procurement operations. It has only one operating conversion plant at Angarsk with a capacity of 18,700 tonnes U/yr. It also has 4 enrichment plants operating in Siberia with a total capacity of 20 million SWU/yr. Two of the facilities are dedicated to provide enrichment services for foreign demand. Fuel fabrication facilities include Ust Kamenogorsk for fuel pellets; Electrostal, Elemash and Novosibirsk for fuel pellets and fuel assemblies, and Chepetsk for zirconium cladding. Fuel assemblies are also being manufactured for export.

Russia is intent on eventually using a closed fuel cycle (fuel reprocessing) for all of its spent fuel. At present, however, large-size spent fuel from commercial reactors of the RBMK and VVER 1000 type is not reprocessed and spent fuel storage capacity is being increased to temporarily keep this fuel. Smaller-sized spent fuel from the naval fleet, from VVER 400 and from the fast BN600 reactor is reprocessed at the Mayak RT-1 plant in Ozersk. Recycled uranium is used in fresh fuel, plutonium is stored, and high level wastes are vitrified and stored. Plans have been approved to modify the reprocessing plant to accept VVER 1000 type fuel.

There is a MOX (mixed plutonium-uranium) fabrication pilot plant at Mayak and there are plans for two commercial facilities in Zheleznogorsk and Seversk.

The process to construct a final waste repository is underway. Site selection studies are focusing on a granite formation at the Kola Peninsula.[60]

REACTOR DESIGN AND SAFETY

The nuclear reactor industry in Russia conforms to a different set of design requirements as those prevalent in reactor licensing in the western hemisphere. The isolation and secrecy required of the early nuclear military activities carried over to the civilian nuclear programme and gave as a result a nuclear industry with major differences in design criteria from that prevalent in the western world. Differences are not constrained to reactor design in itself, but extend to operation philosophy and the perception of what constitute safe systems and safe operating procedures.

Civil reactors in Russia are mostly of two types: the water-cooled, graphite-moderated, channel-type RBMK, based on the military plutonium production reactor design; and the water-moderated, water-cooled vessel-type VVER pressurised reactor, derived from naval propulsion units. The

[60] WNA (2004a).

RBMK is the design of the Chernobyl reactors. It has the particularity of being inherently unstable and difficult to control at lower energies, reasons generally believed to have caused the accident, according to the International Atomic Energy Agency.

Aside from the main reactor types mentioned before, there are also 4 small cogeneration reactors at Bilibino of the EGP type, a variation of the uranium-graphite channel type reactor; and the BN-600 fast breeder reactor. The number of reactors of each type are summarised below.[61]

- 4 first-generation VVER or similar pressurised water reactors considered to have serious design deficiencies.
- 2 second-generation VVER pressurised water reactors with some major design deficiencies that have been partly remedied.
- 8 third-generation VVER pressurised water reactors with full containment structure that have some instrumentation and control system deficiencies, but come closest to western standards.
- 11 RBMK light water graphite reactors, which because of their intrinsic instability are considered unsafe irrespective of the generation type. The 4 plants in Kursk and Leningrad are of some concern being the oldest units of this type. The new unit under construction at Kursk is of this same design.

The accident in Chernobyl widened the perception in Europe and other western nations that the Russian design philosophy is in principle flawed and that actions had to be taken to upgrade the safety of the reactors operating in all of the Former Soviet Union countries including Russia. Following the break-up of the Soviet Union, there have been initiatives from the European Union and from the G-7 group of nations to provide financial aid for this purpose. In re-united Germany the government decided to upgrade the Soviet-designed reactors under construction in East Germany, but these were finally abandoned when no investors were found willing to take on the investment risk. For Soviet reactors in Eastern and Central Europe the G-7 devised an Action Programme to provide assistance to upgrade plants of newer designs, and for short-term improvements to older plants conditional upon commitments to close them down as soon as possible. However, a decade after the agreements little had been accomplished in the direction of providing financing to make modifications and only but a few of the reactors considered to have the highest risk had been shut down. With the accession of 5 Eastern European countries to the European Union in 2004 there have been renewed discussions about what actions to take regarding the fate of Soviet-designed reactors in these nations.[62]

In Russia, talks about its accession to the European Union have recently brought up new requests to boost security in their nuclear installations and to close down the RBMK type reactors considered to be the most dangerous. Russia has begun a programme to modernise and make safety improvements to all of its reactors and the Federal Atomic Supervisory Service, the independent safety regulator, has undertaken the re-licensing of plants of the early generations that due to the procedures existent at the time did not originally obtain unit-specific licenses. With many plants reaching the end of their 30-year lifetime, and with few other alternatives for power generation, the government of Russia is also intent on granting 15-year life extensions to nuclear plants on a case-by-case basis. In a first phase, a total of twelve units were considered for life extensions, requiring major investment funds for their refurbishment. Four of these reactors have already been issued approvals: Novovoronezh 3, Kursk 1 and 2 and Kola 1. Leningrad 1 has been upgraded in preparation for license renewal.[63]

[61] WNA (2004a).

[62] WNA (2004b).

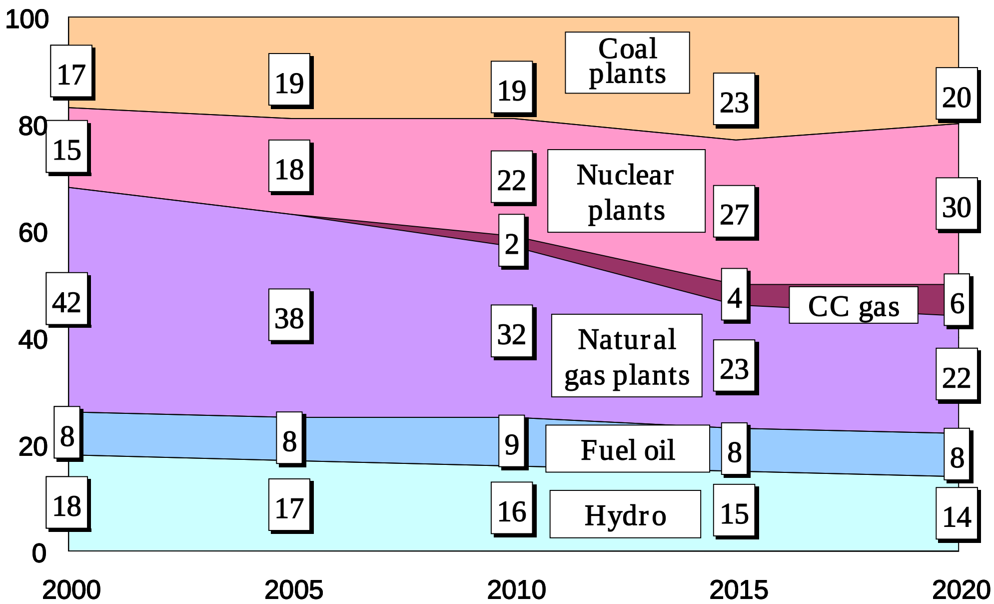
[63] WNA (2004a).

RUSSIA'S NUCLEAR POWER POLICY

Russia's policy for the power generation sector focuses on reinforcing the nation's energy security while enhancing the economic and environmental performance of power plants. Major strategies to diversify fuel supply and improve energy security include an aggressive development of nuclear power, an increase in the participation of coal in the electricity generation fuel mix and the reduction of the excessively high dependence on natural gas.

Natural gas accounts for 64 percent of the electricity generated by conventional thermal plants in the whole of Russia (42 percent of total generation), a figure that goes up to 80 percent in the European part of Russia. This level of dependency is seen as unjustified especially in view of uncertainties in the construction of new natural gas production capacity, a fact that could limit future supply. Further, the government envisions obtaining more benefit from the commercialisation of natural gas to European and Asian markets. Limits will be imposed on the consumption of natural gas in electricity and heat production, and utilisation efficiency will be improved by deploying natural gas-fired gas-steam combined cycle plants to replace inefficient conventional steam cycle units. New nuclear reactors and coal-fired plants will also be built to replace natural gas in the power generation pool. The expanded use of coal will require improving coal quality and stabilising coal production volumes.[64]

Figure 18 Proposed optimisation of Russian power production fuel mix with deployment of nuclear and natural gas combined cycle plants, 2000-2020 (Percentage)



Source: IEP (2003).

The main guidelines of the policy for the future development of nuclear energy in Russia are contained in the *Nuclear Power Development Strategy 2000-2050*, approved by the government on May 2000. The *Strategy* lists some of the desired features of a nuclear sector for the future in Russia, among which are the following:

- Unified complexes integrating: fuel infrastructure, power generation plants and waste treatment facilities at the same site
- Investment policies that provide operational stability and allow for safety improvements and the modernisation of existing capacity, as well as the development of fuel infrastructure, reprocessing and waste management systems

64 IEP (2003).

- Project guidelines that allow implementation of economically feasible hi-tech projects incorporating modern safety and reliability standards and including innovative designs
- Potential to acquire a greater share in the residential sector heat market substituting for fossil fuels
- Availability of specialized equipment and construction capacity

Also, given that the electricity sector in Russia is undergoing a deregulation process, nuclear power plants are required to become competitive players in an open market environment.

The *Nuclear Power Development Strategy* states that the current proven and potential reserves of natural uranium, together with the existing stocks of reprocessed uranium are sufficient to meet the planned development of the nuclear sector in the mid-term under economically sound investment policies and under appropriate export and import schemes. For the long-term, the nuclear energy policy envisages the gradual introduction of fast-breeder technology and making reprocessing of spent fuel a part of the fuel cycle, extending uranium and plutonium resources and further removing limitations on fuel supply in the future.

The plans for the development of nuclear power plants and nuclear fuel cycle facilities and services will require significant investment funds. According to the *Strategy*, the main sources of capital will be:

- Self-finance through a component included in the electricity tariff
- The state budget, and
- Foreign financial sources raised for specific projects with guarantees from the government

Another important component of the government strategy in the nuclear power and fuel cycle sectors is the enhancement of the export potential of nuclear technology, including nuclear reactors, nuclear fuel and nuclear-generated electricity.

FUTURE PLANS

Plans are for nuclear power to increase its share in electricity production from 16.5 percent at present to 25 percent by 2020, while the share from natural gas will be lowered to 28 percent. Efforts will be made to continue increasing capacity factors to approach world standards, targeting 79 percent by 2005, 80 percent by 2010 and 85 percent or more by 2020. Electricity output from nuclear plants is expected to grow to 175 TWh in 2005, 212 in 2010 and 270 in 2020.[65]

The main issues to tackle in nuclear development according to the *Nuclear Power Development Strategy* are to improve the efficiency of plants currently under operation, to increase compatibility among plant designs, to decrease the cost of new capacity additions and to provide an adequate level of safety commensurate with modern standards.

The current investment programme totals US$ 15 Billion (2002 US$) from today up to the year 2010.[66] In order of importance, the investment priorities in the nuclear sector are: [67]

- Safety improvements for existing nuclear plants
- Upgrade, renovation and lifetime extension of 1st and 2nd generation power plants
- Operational efficiency improvements to nuclear fuel cycle facilities and services
- 5.5 GW of new power plants, with funds assigned to 6 plants presently under construction

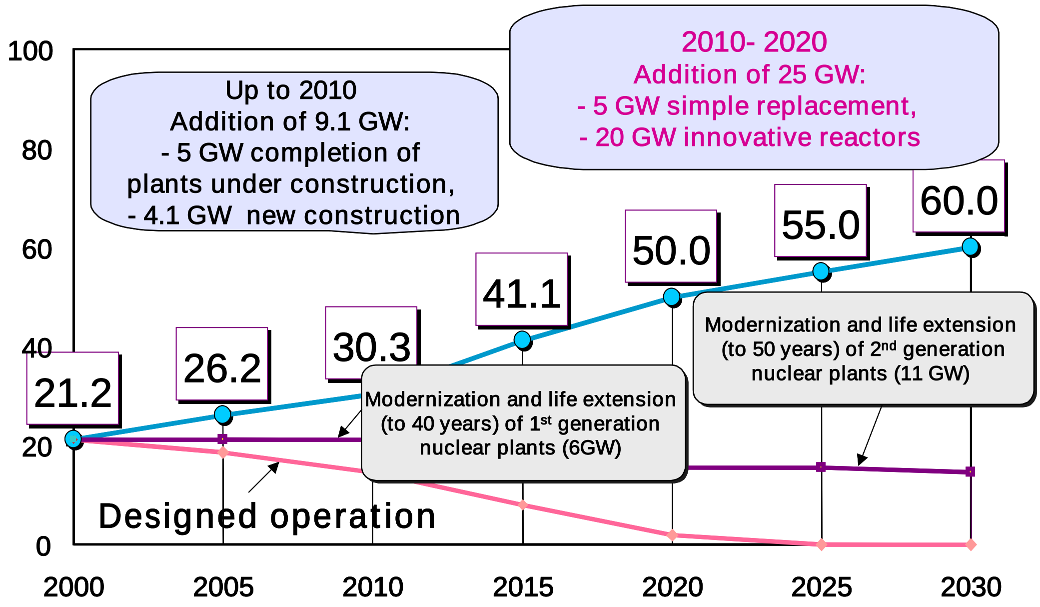
[65] WNA (2004a).

[66] WNA (2004a).

[67] IEP (2003).

- Replacement of 6 GW of 1st generation nuclear reactors with new plants at the same site
- Deployment of advanced nuclear technology (fast breeders, uranium-plutonium fuel, cogeneration plants, advanced designs)

Figure 19 Russian nuclear power development strategy up to 2030 (GW)



Source: IEP (2003).

Thirty-five percent of the presently planned investment budget will be used for upgrading existing plants and replacement capacity, and 56 percent will be assigned to new capacity. Financing for the construction of 5.5 GW of capacity has been secured, with priority having been assigned to restarting the construction of 6 of the 18 plants whose construction had been interrupted earlier due to financial reasons. Of the 6 restarted constructions, the Kursk-5 RBMK type reactor has been halted again with no clear indication about its possible future. Another restarted unit is the BN-800 fast reactor that will replace the BN-600 unit 3 at Beloyarsk in 2010. Total nuclear installed capacity is expected to be 35 GWe by the year 2020 in a low growth scenario and as much as 50 GWe in a high growth scenario.[68]

For the replacement of aging units, the strategy is to construct plants of newer technologies at the same site locations. For new additional capacity, the Nuclear Power Development Strategy favours construction in the European region of the nation to optimise the power load curves in the winter months and to improve the fuel mix structure in that area. A regional power policy has been laid out to optimise the fuel mix structure as follows for each area of the nation.

In the European region:

- Modernisation of fossil fuel power plants with deployment of combined cycle steam-gas turbines.
- Aggressive deployment of nuclear power plants

In Siberia:

- Deployment of both coal-fired and hydropower plants

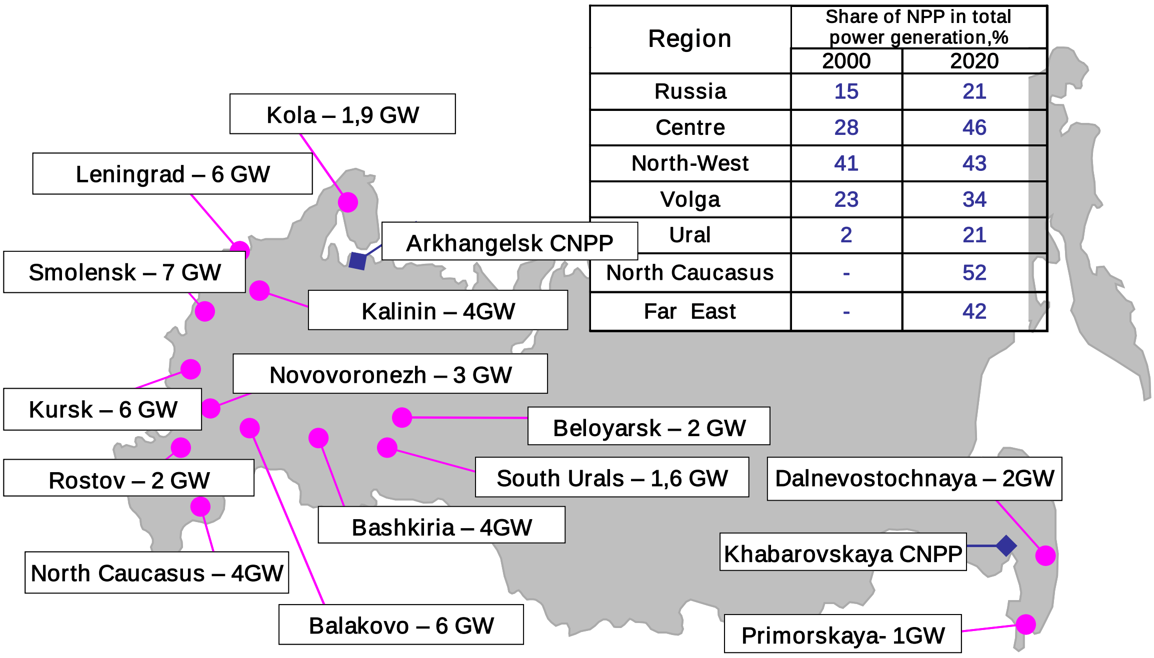
[68] WNA (2004a).

In the Far East:

- Deployment of hydropower and coal-fired plants
- Development of natural gas fuelled cogeneration power plants for large municipal energy supply

According to government plans 20 GW (mostly all) of new installed capacity besides that of restarted constructions, should be of new generation advanced reactor designs, with 10 GW more by 2030.[69]

Figure 20 Deployment of nuclear power plants proposed in the Russian Energy Strategy



Region	Share of NPP in total power generation,%	
	2000	2020
Russia	15	21
Centre	28	46
North-West	41	43
Volga	23	34
Ural	2	21
North Caucasus	-	52
Far East	-	42

Note: Blue marks denote combined heat and power plants.
Source: IEP (2003).

In addition to reactors for electricity generation, the government plans the installation of reactors for the production of heat for district and industrial use. Four 500 MW units are planned in Arkhangelesk between 2009-2016; 2 units in Voronezh between 2010-2018, other units in Saratov and Dimitrovgrad, and small 40 MW units at Chukoyka and Severodvinsk for a total of around 5,000 MW of thermal energy.[70]

The Nuclear Power Development Strategy envisions the development of nuclear power in the 21st century following a path with three distinctive periods:

- The incremental period, 2000-2020

  A period where significant changes are unlikely due to the present structural problems in the electric power sector. The period will be characterised by improvements in efficiency and safety at existing plants and the utilisation of existing weapon plutonium stocks in electricity generation. During the period advanced designs of thermal (conventional low-energy) type electric power reactors will be developed and likely deployed. Spent fuel disposal facilities will be developed to address security and IAEA non-proliferation standards.

- The start of rapid growth period, 2020-2030

[69] IEP (2003).
[70] WNA (2004a).

The period will be characterised by a five-fold increase in nuclear power generation. Fuel cycle technology would be similar to the current one with heavy utilisation of military plutonium stocks for power generation and using a once-through type cycle (no spent-fuel reprocessing). Nuclear technology would comprise mainly advanced thermal reactors with characteristics designed for specific applications, such as high temperature reactors, small capacity reactors, reactors for hydrogen production and desalination. A comprehensive international programme would be pursued for the long-term final geologic disposal of high-level waste. The period will also feature the construction of demonstration reactors of a closed fuel cycle type including breeding of nuclear material and spent fuel reprocessing.

- The new technology period, 2050-2100

  The new technology period will be characterised by the substantial deployment of economically competitive innovative reactor designs and fuel cycle technologies, such as: high-temperature gas cooled reactors; molten salt reactors; fast (high-energy) breeding reactors with liquid-metal or gas cooling, operating on uranium-plutonium or uranium-thorium cycles; and multiple-actinide fast reactors that reduce high-level waste volumes and breed new fuel material. During the period, international collaboration efforts will have to be directed at creating mechanisms and infrastructure for an effective non-proliferation regime.

RESEARCH AND DEVELOPMENT

Russia is active in the development of advanced and innovative reactor designs. The reactor presently being deployed in Russia is the V-320 version of the VVER 1000 design. A V-428 version of the same unit featuring western control systems has been exported to China and installed at the Tianwan nuclear plant. The V-392 is an advanced version of the VVER 1000 reactor under development and has been sold to India. This same type will probably be used for units 6 and 7 at Novovoronezh. The V-407 with advanced safety features is a smaller scale VVER 640 developed jointly with Siemens (now Framatome ANP).

Rosatom is now developing also a larger scale version of the Russian pressurised water reactor called the VVER-1500. The larger capacity design will be used at Kursk and Leningrad, with the first unit expected to start construction at Leningrad in 2005.

Development continues on fast (high-energy) reactors too. The BN-600 reactor has been in operation at Beloyarsk since 1980 and a larger scale 750 MW replacement is already under construction at the same site. The project might have future involvement from the governments of Japan and China.

A fleet of nuclear ice-breakers has been operated by Russia for more than 40 years in the waters of the Artic Sea. The first such ship was launched in 1959 using a reactor that was developed for this purpose in 1955. Today new generation nuclear reactors are being developed for ice-breakers that will be launched after 2015.

With the experience accumulated over many years of operation, these naval propulsion reactors are now being proposed as a kind of low-capacity floating power plant to be used in cold, remote areas where conventional nuclear plants would be impractical for reasons of cost and long duration of construction. Studies by nuclear specialists and shipbuilders have shown the possibility of using these ship reactors to produce heat and electricity commercially. The small reactors and their steam turbine can be installed on a barge or on several pontoons either on land or water, could be developed in a relatively short time and can be manufactured in Russian factories in 4 to 5 years. One such floating plant has been developed to provide electricity and heat to Severodvinsk, in the Arkhangelsk region. Russia plans to export versions of this reactor for floating desalination plants, with many developing nations having expressed interest in purchases or in establishing joint partnerships for development and construction.[71]

Other research is directed at extending the burn-up capacity and energy delivery of nuclear fuel to bring it closer to Western performance standards. With higher enrichments and the inclusion of burnable poisons, fuel lives have been extended and operating costs have been lowered. Research continues and more improvements in fuel design are envisioned for the future.

71 Novosti (2004).

KOREA

BACKGROUND

In the last few decades, Korea has been one of Asia's fastest growing and most dynamic economies. Its GDP has averaged a notable annual growth rate of 7.2 percent between 1980 and 2001. In that year its per capita income reached US$ 14,187 (1995 US$ at PPP), three times the value in 1980. [72]

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. Its indigenous resources of coal and gas are very limited, and it has no oil reserves. Korea depends on energy imports for 82 percent of its primary energy needs. Total primary energy supply in 2001 was 190 Mtoe and the per capita energy consumption was 3.1 toe. [73]

The annual electricity demand growth rate averaged 10.9 percent between 1980 and 1999.[74] Nuclear power is the largest generation source in Korea accounting for 40 percent of power production in 2003. Coal follows at 38 percent, gas at 13 percent, oil at 5 percent, and hydropower and others at 4 percent.[75]

CURRENT SITUATION OF NUCLEAR POWER

Korea is the APEC economy with the highest percentage of electricity coming from nuclear power (40 percent). It generated 130 TWh by nuclear means in 2003 and currently has an installed nuclear capacity of 16,716 MW coming from 19 reactors, the last of which began commercial operation only recently at Ulchin in July 2004. Another 1,000 MW reactor under construction at Ulchin will be started by the end of 2004, while four more began construction between July and September of 2004. Additionally, another four reactors are in the preparation stage.

The reactors, along with the hydro plants in Korea, are owned and operated by Korea Hydro and Nuclear Power Company (KHNP), a state owned utility.

Table 13 Nuclear power data summary, Korea

Reactors in operation	19
Nuclear installed capacity (gross)	16,716 MW
Reactors under construction	5
Total electricity generation	322.4 TWh
Nuclear generation	129.7 TWh
Nuclear generation share	40 %

Note: Generation figures for 2003.
Source: KPX (2004), IAEA (2004).

Korea became a member of the IAEA in 1957. The Atomic Energy Law was promulgated in 1958 and one year later the Office of Atomic Energy was established to head the economy's activities in developing peaceful uses for atomic power. Korea embarked in the construction of Kori Unit 1, its

[72] EWG/APERC (2003).
[73] EWG/APERC (2003).
[74] APERC (2002).
[75] KPX (2004).

first commercial nuclear reactor, in 1971. Eight reactors followed in the 1980s, seven in the 1990s and three more after the year 2000.

Figure 21 Location of nuclear power plants in Korea

Source: Perry-Castañeda Library Map Collection.

The earlier nuclear plants were constructed as turnkey projects. The technology used for these rectors was acquired from Combustion Engineering of United States, Framatome from Europe, and Atomic Energy of Canada Limited (AECL). For later reactors, however, Korea pursued a path of technological self-sufficiency in design, manufacture and management in line with the nation's industrialisation policy. After the decision was made in 1985 to become more technically self-sufficient, many new projects have involved more participation from domestic contractors and have included terms for technology transfer from foreign contractors and major equipment suppliers. The strategy had the ultimate goal of producing a standardised design incorporating a high degree of self-reliance on which the construction of future plants was to be based, minimising costs and construction times.

Combustion Engineering's System 80 PWR design was selected as the basis for a standardised concept and was used for the first time at units 3 and 4 of the Yonggwang nuclear plant, constructed jointly by Hanjung (Korea Heavy Industries and Construction Co.) and ABB-Combustion Engineering. The standardised concept evolved finally into the Korea Standard Nuclear Power Plant (KSNP), a 1,000 MW advanced reactor incorporating features from the United States Electric Power Research Institute's (EPRI) Advanced Light Water Reactor design. It was used in units 3 and 4 at Ulchin nuclear plant, which were commissioned in 1998 and 1999 respectively, and replicated in all subsequent large 1,000 MW reactors. Hanjung was privatised in 2001 and subsequently changed its name to Doosan Heavy Industries and Construction, the name under which it constructed the last 4 KSNP reactors at Yonggwang and Ulchin.

CANDU reactors from Canadian design were selected for the Wolsong site, the last three units of which entered service in the late 1990s and were constructed jointly with AECL in a similar effort to absorb the technology and develop local expertise.

Table 14 Nuclear power reactors in operation and planned in Korea

Name	Type	Supplier	Gross Capacity (MWe)	Commercial Operation
Operational				
Kori 1	PWR	Westinghouse	587	Apr. 1978
Wolsong 1	PHWR (CANDU)	AECL	679	Apr. 1983
Kori 2	PWR	Westinghouse	650	Jul. 1983
Kori 3	PWR	Westinghouse	950	Sep. 1985
Kori 4	PWR	Westinghouse	950	Apr. 1986
Yonggwang 1	PWR	Westinghouse	950	Aug. 1986
Yonggwang 2	PWR	Westinghouse	950	Jun. 1987
Ulchin 1	PWR	Framatome	950	Sep. 1988
Ulchin 2	PWR	Framatome	950	Sep. 1989
Yonggwang 3	PWR (System 80)	Hanjung/ABB-CE	1000	Mar. 1995
Yonggwang 4	PWR (System 80)	Hanjung/ABB-CE	1000	Jan. 1996
Wolsong 2	PHWR (CANDU)	AECL/Hanjung	700	Jul. 1997
Wolsong 3	PHWR (CANDU)	AECL/Hanjung	700	Jul. 1998
Ulchin 3	PWR (KSNP)	Hanjung/ABB-CE	1000	Aug. 1998
Wolsong 4	PHWR (CANDU)	AECL/Hanujung	700	Oct. 1999
Ulchin 4	PWR (KSNP)	Hanjung/ABB-CE	1000	Dec. 1999
Yonggwang 5	PWR (KSNP)	Doosan	1000	May. 2002
Yonggwang 6	PWR (KSNP)	Doosan	1000	Dec. 2002
Ulchin 5	PWR (KSNP)	Doosan	1000	Jul. 2004
Under construction				
Ulchin 6	PWR (KSNP)	Doosan	1000	2005
Shin Kori 1	PWR (KSNP+)	Doosan	1000	2008
Shin Kori 2	PWR (KSNP+)	Doosan	1000	2009
Shin Wolsong 1	PWR (KSNP+)	Doosan	1000	2009
Shin Wolsong 2	PWR (KSNP+)	Doosan	1000	2010
In preparation				
Shin Kori 3	PWR (APR 1400)	-	1,400	2010
Shin Kori 4	PWR (APR 1400)	-	1,400	2011
-	PWR (APR 1400)	-	1,400	2014
-	PWR (APR 1400)	-	1,400	2015

Source: MOCIE, Korea.

After the regulatory reforms in the electricity sector that brought about the break-up of the power generation segment of the Korea Electric Power Corporation (KEPCO), the nuclear power plants together with the hydro plants came under the control of the Korea Hydro and Nuclear Power Company (KHNP). KHNP is also responsible for the management of radioactive wastes coming from all of its plants. Plans exist for the construction of centralised facilities for both spent fuel and low and intermediate level radioactive wastes (LILW), but for the time being these materials are being stored on-site at each of the power plants.

KOREAS' NUCLEAR POWER POLICY

Korea's energy policy for the most part is centred on achieving a reliable energy supply to support its fast economic growth. Korea is highly dependent on foreign sources for its energy needs making it vulnerable to energy crises, and it is particularly dependent on the Middle East for oil and natural gas.

In response to this the Ministry of Commerce, Industry and Energy (MOCIE) is promoting a policy of decreasing dependence on petroleum and increasing the use of LNG, nuclear energy and bituminous coal.

Sustainable development is of late increasingly becoming a major focus of the energy policy of Korea and nuclear power is considered an important part of the strategy to achieve it. According to *Energy Policies of Korea*, a policy document published by MOCIE in January 2004, the government intends to maintain a certain share of nuclear energy in the power generation sector to establish an environment-friendly low-carbon energy consumption system.[76]

A third important element in Korea's nuclear policy is support for the national industry. Since shortly after its beginnings, the nuclear power programme has included as a major component the in-house development of key technologies for the design, construction and operation of its nuclear plants. This policy stems from Korea's industrialisation directives and seeks the establishment of a national nuclear industry. Owning a mature nuclear industry was originally intended to lessen the nation's dependence on foreign technology in the energy sector, but has of late been imbued with the added dimension of pursuing international export markets.

As part of this export-oriented nuclear policy, KHNP participated in the construction and commissioning of one of the CANDU units at the Qinshan nuclear plant in China. KHNP has also provided consulting and operator training services for the operation of nuclear plants at Qinshan and Daya Bay in China, and Cernavoda in Romania. As well, KHNP collaborated with the Government of Vietnam in the evaluation studies for the possible introduction of nuclear power in that economy; and recently in February of 2004 announced a Memorandum of Understanding with the Government of Indonesia to jointly analyse their nuclear prospects.

In the Democratic People's Republic of Korea (North Korea) two reactors of the KSNP design were to be constructed by the Korean Peninsula Energy Development Organisation (KEDO), a group consisting of the United States, South Korea, Japan, the European Union and 9 other economies. The construction was contracted to KEPCO as a turnkey project, but at the moment the finalisation of the project is in question after KEDO decided to suspend activities for one year in December 2003 in response to the announcement by North Korea that it had decided to pursue a programme for the production of nuclear weapons. Recently in 2004, KEDO decided to extend the suspension for another year.

Korea has also been active promoting cooperation in nuclear energy within the APEC organisation. It proposed to APEC energy ministers at their 5th Energy Ministers Meeting to expand the scope of APEC energy cooperation activities to include nuclear energy. It also launched in April 2004 an annual training programme at its own expense for nuclear engineers and policy-makers from APEC member economies. And recently, in collaboration with Mexico, Korea developed a framework for discussion of nuclear energy within the Energy Working Group of the APEC organisation which obtained the endorsement of APEC energy ministers at their 6th Energy Ministers Meeting.

FUTURE PLANS

The MOCIE's *First Basic Plan of Long Term Electricity Supply and Demand*,[77] projects an annual electricity demand growth rate between 2002 and 2015 of 3.3 percent and shows plans for a total of 28 nuclear units by the year 2015 (as shown in Table 14), the latter of which will sport domestic advanced designs.

A sign of the times, and an indication of possible difficulties ahead, is the recognition by the MOCIE in its *Toward 2010: Energy Policies* document[78] that it will become increasingly difficult to secure sites and construct nuclear plants in the future. It is widely believed in Korea that this factor

76 MOCIE (2004a).
77 MOCIE (2002).
78 MOCIE (2004b).

can delay somewhat the official plans for new plant construction, particularly in those cases that will require the selection of new sites.

To enhance public acceptance, the government of Korea has an assistance system for neighbouring areas to power plants of all types contained in the *Law for the Support of Neighbouring Areas to Power Plants*. The programme includes compensations in the form of government grants to support regional development projects and subsidies in electricity tariffs, in addition to the implicit benefit of a certain number of job openings for local residents.

In 2003 residents in Buan staged strong protests in response to the local government's plans to build a waste facility in the nearby island of Wido (located next to the Yonggwang nuclear plant). Perhaps in view of this, and in order to make the construction of nuclear installations more attractive, grants or compensation limits have been raised for communities hosting multiple nuclear power plants or a nuclear waste facility. MOCIE specifies that the compensation for a community willing to host a radioactive waste site is in the order of US$ 260,000, or the amount equivalent to that given to several communities hosting 3,800 MW worth of conventional plants, or to 4-6 communities hosting one conventional plant each.

The site selection process for waste installations around the nation is currently underway, and petitions have already been received from 11 local governments.[79] A petition can be formulated by a local government or the community itself with the approval or signature of 1/3 of the local residents. However, according to recently revised rules, the petition will only be considered a formal application once the totality of the residents communicate their consent by way of public hearings and a local vote. Following residents' approval, the central government will proceed with a technical selection of the best suitable site for a low and intermediate level radioactive waste (LILW) storage facility among the applications received.

This site will be constructed by 2008 and operated by KHNP and will handle all the nation's LILWs. The disposal facility will be of either a vault or cavern type, to be decided depending on the site, with an initial capacity of 100,000 drums and an eventual total capacity of 800,000 drums.

As for spent fuel, KHNP is also planning a centralised interim storage facility with a total final capacity of 20,000 tonnes of either a wet or dry type to be operational by the year 2016 hosting spent fuel from all of Korea's nuclear plants. There is no commitment yet as to whether permanently dispose of spent fuel or reprocess it to obtain plutonium or unused uranium, and therefore only plans for an interim storage installation exist.

RESEARCH AND DEVELOPMENT

Research and development activities include continuing advancement of Korea's commonly used reactor design types. Of current interest are the improved KSNP and the APR 1400 reactor designs.

The improved KSNP or KSNP+ programme was aimed at incorporating technical enhancements to the design and making the reactor more competitive and suitable for international marketing. KHNP cites enhancements in safety that will render an 11 percent lower probability of core damage compared to the previous type and cost advantages that will make it competitive with coal-fired power generation. This design is the basis for the reactors that are to begin construction in the 2nd half of 2004 at Shin Kori and Shin Wolsong.

The APR 1400 is an evolutionary advanced light water reactor based on the KSNP and scaled-up to 1,400 MW. Different from previous Korean designs, the APR incorporates all of the United States EPRI advanced light water reactor requirements, and as an evolutionary advanced reactor concept, aims at improved safety, reliability, and economics. Capital cost for a first-of-a-kind unit is expected to be of around US$ 1,400/kW, with subsequent units carrying a cost closer to US$1,200/kW. Units 3 and 4 to be constructed at the Shin Kori site by 2010 and 2011 will bear this design, as well as two other reactors to be operational by 2014 and 2015 at a yet to be designated new site.

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[79] MOCIE (2004c).

Korea is also active in the United States' led Generation IV International Forum (GIF) and the IAEA's International Project on Innovative Nuclear Reactors and Fuel Cycles (INPRO).

In connection with waste management, research is being conducted on waste treatment and on waste disposal technology. Vitrification tests have been conducted in a pilot scale facility since 1999, and a prototype vitrification plant labelled the world's first is planned at the Ulchin site for LILWs by 2007. In the area of waste disposal technology, research is ongoing on near surface disposal facilities as regards to site characterisation, safety and environmental assessments and site monitoring. A near-surface pilot facility is being constructed to test the performance and safety of engineered barrier systems.

CANADA

BACKGROUND

The economic conditions in Canada have been generally positive in recent years. Although growth was stifled for a short period around 2001 along with that of the United States, it recovered from an annual figure in 2001 of 1.9 percent to 3.3 percent in 2002. GDP per capita in 2001 was US$ 25,841 (1995 US$ at PPP) and unemployment averaged 7.2 percent in the same year.[80]

Canada is the fifth largest energy producer in the world, and is a major energy exporter. It has abundant reserves of oil, oil sands, natural gas, coal and uranium in its western provinces and enormous hydropower resources in Quebec, Newfoundland, Manitoba and British Columbia. In 2001 energy reserves included 680 million cubic meters of crude oil, 27,770 million cubic meters of oil in oil sands, 1,615 billion cubic meters of natural gas and 6,294 million tonnes of coal.[81] Canada's proven reserves of uranium are the world's third largest behind Australia and Kazakhstan at 437 thousand tonnes,[82] but it ranks first in high-grade uranium deposits. Canada's speculative resources are double the proved reserves, at 700 thousand tonnes.[83] Canada is also the world's largest producer of uranium, turning out 11,604 tonnes of uranium in 2002 and accounting for about one-third of the world's output.[84]

Energy production is 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. Total primary energy supply in 2001 amounted to 262 Mtoe. Per capita final energy consumption is four times the APEC average and higher even than that of the United States at 6.0 toe. This is due to the high standard of living, cold climate, long distances between major cities and Canada's many energy intensive and bulk good industries.[85]

A large portion of Canada's oil, gas and uranium production is exported. Seventy-percent of the crude oil production in western Canada was sold abroad in 2001. Net exports result in only 28 percent of production after accounting for the 58 Mtoe of crude that is imported into Canada's eastern territories. As for natural gas, 56 percent of production was exported in 2001. During the 1990s net oil exports grew an average of 3.6 percent yearly while net natural gas exports grew by 9.2 percent per year. Long-term prospects for oil and gas exports remain bright due to robust demand in the United States, expanding pipeline capacity and continued discoveries.[86] Uranium is also a main export, with 80 percent of the production being exported annually mainly to the United States and France. After peaking in 1996, uranium exports declined both in terms of volume and value until recovering again in 2000 and 2001.[87]

Following the relatively minor variations of economic growth in Canada's recent past, electricity demand growth between 1980 and 1999 has fluctuated around a moderate annual average of 2.42 percent.[88] The nuclear share in power generation in 2003 was a significant 12.5 percent.[89] Hydropower predominates in electricity generation with a 57 percent share, followed by thermal plants with 30 percent.[90]

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80 EWG/APERC (2003).

81 EWG/APERC (2003).

82 NEA/IAEA (2002).

83 NEA/IAEA (2002).

84 CNA (2004a).

85 EWG/APERC (2003).

86 EWG/APERC (2003).

87 CERI (2003).

88 APERC (2002).

89 IAEA (2004a).

90 EWG/APERC (2003).

CURRENT SITUATION OF NUCLEAR POWER

In February 2004, Canada had 17 reactors in operation and 3 more undergoing overhaul procedures. These 17 reactors generated in 2003 1/8th of Canada's total electricity. Of the total number of reactors, 18 are in the Ontario province and generate more than half of its electricity. Canada's nuclear programme is based on a heavy water natural uranium reactor system developed by Atomic Energy of Canada Limited (AECL) called CANDU (acronym for Canada Deuterium Uranium). This type of reactor is different from other reactors in the world in that they utilise heavy water (deuterium dioxide), and natural uranium without the need for enrichment.

Table 15 Nuclear power data summary, Canada

Reactors in operation	17
Nuclear installed capacity (gross)	12,807 MW
Reactors under construction	0
Total electricity generation	560.9 TWh
Nuclear generation	70.3 TWh
Nuclear generation share	12.5%

Note: Generation figures for 2003.
Source: IAEA (2004).

With the beginning of deregulation of the electricity market in Ontario in April of 1999, Ontario Hydro, the province's power company, was divided into five separate entities of which Ontario Power Generation (OPG) became the owner of 85 percent of total generation assets in the province. Ownership of Ontario's reactors remained under the hands of the OPG, which is still totally owned by the Province of Ontario. By 2010 the company will be required to reduce its provincial market generation share from the 85 percent it holds at present to 35 percent. The operation of two of its nuclear stations, Bruce A and Bruce B with 4 reactors each, has been leased for a period of 18 years to Bruce Power, now a Canadian consortium, since May 2001. The Point Lepreau nuclear station in New Brunswick is operated by New Brunswick Power Nuclear Corporation, and the Gentilly 2 Nuclear Generating Station by the provincial government of Quebec's Hydro-Québec.

Canada is the world's leading producer and exporter of uranium. Uranium exploration started in Canada in 1942. The focus of uranium exploration and production activities has shifted from the Northwest Territories and Beaverlodge, Saskatchewan in the beginnings; to Blind River/Elliot Lake in Ontario for a long productive period; and finally back to Saskatchewan. After 40 years of very prolific uranium production in the Elliot Lake area of Ontario, activities ended with the closure of the Stanleigh mine in 1996 and now the Athabasca Basin in Saskatchewan is the sole producer of uranium in Canada. In 2002 all production from Canada came from higher-grade lower-cost production centres at Key Lake, Rabbit Lake, Cluff Lake, McLean Lake and McArthur River in Saskatchewan's Athabasca Basin. After a policy to phase out uranium mining by the then governing party in the early 1990s, the current government in Saskatchewan perceives advantages to be gained by the local economy and actively encourages and supports the activity, exacting from the producers proper practices to minimise environmental impact.[91]

In April 2003 heavy flooding caused the temporary shutdown of operations at McArthur River, the world's most productive uranium mine. Water pouring in from a new development gallery impeded operations and flooded the mine's mill, requiring the construction of barriers to contain the water and plugging the inundated passage with concrete. A rapid recovery allowed Cameco

[91] NEA/IAEA (2002) and IAEA (2003).

Corporation to resume operations by July and to end the year with an estimated total production of between 6,000 and 6,500 tonnes of uranium.[92]

Figure 22 Location of nuclear power plants and main uranium mining centres in Canada

Source: World Nuclear Association.

Other fuel cycle activities in Canada include one uranium refining plant in Blind River, and a conversion facility in Port Hope; both in Ontario and owned by Canada's largest uranium producer: Cameco Corporation. The conversion facility produces 10,500 tonnes worth of uranium in the form of uranium hexafluoride (UF_6) for export. UF_6 is the form of uranium used for enrichment, an additional process required when uranium is used in reactor designs most everywhere else in the world. Two fuel fabrication plants with a total capacity of 1,900 tonnes of uranium cover the nation's own reactor requirements.

Canada up to now has produced all of its heavy water needs domestically, but recently in 1997 the last of Canada's heavy water plants was shutdown. Ontario Power Generation has an inventory of heavy water more than enough to support the operation of its nuclear plants during their full lifetimes, and has expressed its intent on selling surplus amounts. At the same time, the utility estimates that heavy water could be purchased from third parties if the operating lives of its nuclear stations were eventually extended into the future.[93]

Spent fuel from Canada's power plants is kept for a few years in water-filled bays inside the stations. Each nuclear generating facility in Ontario Power Generation has sufficient capacity to store used nuclear fuel for as much as 15 to 20 years of operation. After being stored for the cooling-off period of at least 10 years, the fuel bundles are transferred from the wet bays to large above ground

[92] CNA (2004a).

[93] OPG (2004).

concrete silos at the corresponding nuclear site, a method sometimes referred to as local dry storage. The Pickering and Bruce sites have dry storage facilities while a similar provision for the Darlington site is being planned for 2007.

There is no facility for permanent disposal of used nuclear fuel currently in operation in Canada. A Nuclear Waste Management Organisation set up by nuclear operators in Canada is currently analysing possible options for an integral solution and is expected to submit a final report by 2005. A large underground storage facility for final disposal, for which designs have been developed, is one of the options being considered.

Canada has commercialised the CANDU type reactor technology abroad: there are four reactors of the type operating in Korea, two in China, and one each in Argentina and Romania. The reactors in China are the most recent: Unit 4 of the Qinshan Phase III nuclear project near Shangai started up in December 2002 and Unit 5 in July 2003.[94] According to AECL, both units were constructed under budget and ahead of schedule.

In addition, one more CANDU reactor is under construction at the Cernavoda site in Romania. Early in 2003 financing to complete this second CANDU reactor was approved, and the unit is expected to enter service in 2007. The first reactor at the same site has been operating since 1996. Each reactor will supply approximately 10 percent of Romania's electricity supply. A long-term strategy in Romania is being developed to complete in the next ten years another two of the total of five CANDU reactors that were initiated between 1980 and 1982 in Cernavoda and stopped afterwards in 1991 due to a lack of financing funds.[95]

REACTOR SHUTDOWNS AND LIFETIME EXTENSIONS

Between 1995 and 1998, 4 reactors at the Bruce nuclear plant and 4 more at the Pickering nuclear plant were laid up for refurbishment focusing on increasing performance and safety characteristics that had reportedly been gradually declining due to a lack of proper maintenance and to deteriorating equipment. During the lay-up period there were repeated discussions about retiring the reactors permanently. On one such occasion in January 2002 OPG announced that re-powering its nuclear reactors would be a more economical way to meet Ontario's needs weighed against the cost of building natural gas-fired plants, at the same time avoiding having to buy power from existing coal-fired plants in Canada and the United States. The low operation costs of its nuclear stations would also help keep power prices competitive as Ontario was preparing to open its electric market to competition on May 1 of that year.[96]

By the time of the blackout that affected areas of Ontario and New York in August 2003, only one reactor had been brought back online. Summer demand and later the blackout pointed to the severity of the situation without the missing capacity and prompted the accelerated restart of reactors that were still idled by then. The Province of Ontario, which had been an exporter of power to New York State, had to resort to renting diesel generators to cope with the demand of the summer months. The reduced capacity margin existent during the blackout was cited as the cause for the slow recovery of the Ontario system, which took days to be normalised while by comparison the system in New York was back in full operation within 30 hours.[97] By April 2004, 1 reactor at Pickering and 2 reactors at the Bruce plant had been restarted. Three more reactors at Pickering are still undergoing refurbishment with plans to be restarted soon, and 2 reactors at the Bruce plant have been laid up indefinitely.

Hydro Quebec is evaluating the feasibility of refurbishing Gentilly-2 to extend its operating life by 25-30 years beyond its original life expectancy to 2013. New Brunswick Power is also currently

[94] CNA (2004a).

[95] CNA (2004a).

[96] Reuters (2002).

[97] The Globe and Mail (2003).

planning to refurbish its sole reactor between 2006-2008 with the intention of extending the plant's life to the year 2032.[98]

Table 16 Nuclear power reactors in operation in Canada

Name	Type	Location	Gross Capacity (MWe)	Date Connected
Bruce-3	PHWR	Ontario	825	12/12/1977
Bruce-4	PHWR	Ontario	825	12/21/1978
Bruce-5	PHWR	Ontario	840	12/2/1984
Bruce-6	PHWR	Ontario	840	6/26/1984
Bruce-7	PHWR	Ontario	840	2/22/1986
Bruce-8	PHWR	Ontario	840	3/9/1987
Darlington-1	PHWR	Ontario	935	12/19/1990
Darlington-2	PHWR	Ontario	935	1/15/1990
Darlington-3	PHWR	Ontario	935	12/7/1992
Darlington-4	PHWR	Ontario	935	4/17/1993
Gentilly-2	PHWR	Quebec	675	12/4/1982
Pickering-4	PHWR	Ontario	542	5/21/1973
Pickering-5	PHWR	Ontario	540	12/19/1982
Pickering-6	PHWR	Ontario	540	11/8/1983
Pickering-7	PHWR	Ontario	540	11/17/1984
Pickering-8	PHWR	Ontario	540	1/21/1986
Point Lepreau	PHWR	New Brunswick	680	9/11/1982

Source: IAEA (2004a).

CANADA'S NUCLEAR POWER POLICY

The federal government regulates the development and application of nuclear energy in Canada, but the provinces and the provincial electric power utilities have authority over the planning and operation of nuclear plants. The federal government supports the nuclear power option and provides funding for Atomic Energy of Canada Limited (AECL), the economy's major nuclear research and development organisation.

The three provinces with nuclear plants have at present no plans for more units, but have either refurbished their plants for extended lives or are planning to do so. Both at the federal and provincial levels the notion exists that nuclear energy can be an important component of the electricity system helping to meet future demand and aiding Canada in meeting its targets for emissions reductions. In Ontario, the most populous province in Canada, an Electricity Conservation and Supply Task Force was formed by the government to make recommendations regarding electricity supply options for the future. The panel presented in early 2004 the results of investigations conducted during 2003, which included the recommendation to meet future electricity requirements with a range of energy efficiency and conservation programmes, renewable energy where appropriate, and construction of new natural gas and nuclear generating stations.[99]

R. John Efford, current Minister of Natural Resources in the Federal Cabinet of Canada, stated in January 2004 that the use of nuclear power is a clean environmental way to produce electricity and that he supported deploying more nuclear reactors to meet Canada's and Ontario's needs.[100]

[98] COG (2004).

[99] CNA (2004a).

[100] The Globe and Mail (2004).

AECL, a federal agency, in December 31 announced a Can$ 12 billion proposal for the construction of 8 new reactors in Ontario over the next 20 years to meet the province's electricity demand. The present government in Ontario has pledged to close a number of coal-burning generating stations by 2007 that represent around 4,000 MW of lost capacity. In addition, it is estimated that by the year 2020 all of Ontario's nuclear plants, if not refurbished, would reach the end of their lifetimes.

Officials of AECL justified their proposal on the fact that there would be a major gap in electricity supply in the next 15 to 20 years in the province. At an electricity demand growth rate of 1 percent per year, the removal of coal and nuclear plants would leave Ontario with the need to overhaul 21,000 MW of capacity. The proposal states that refurbishing the existing nuclear plants would reclaim about 11,700 MW and that renewable energy along with natural gas generators would fill some of the need for more capacity. There would still be a 5,500 MW void which the proposal intends to fill with 4 pairs of CANDU reactors of 1,400 MW of capacity per pair of the type recently finished under budget and ahead of schedule in China, or being constructed in Romania. Alternatively, the new reactors could be of the advanced CANDU reactor (ACR) type being developed and estimated to be available in two or three years' time. ACRs would be capable of generating electricity at a cost of 4.4 Canadian cents/kWh, which would be less than the cost of natural gas fired plants or wind energy. The proposal includes the formation of a vendor group by AECL that would secure financing and offer the units for sale at a firm price and a guaranteed schedule, taking most of the risk of the operation away from the purchaser, in contrast with past experience where the Ontario utility was responsible for the cost overruns during construction.[101]

For their own part, Bruce Power announced in a speech by its CEO in January 29, 2004, that it had plans to return indefinitely laid-up Units 1 and 2 back to service adding 1,500 MW to the electricity system by 2006 or 2007. Further, it announced plans to evaluate the business case of extending the lifetimes of their 4 units at Bruce B and the potential of building one or two more new reactors at the same site.[102]

With the Nuclear Fuel Waste Act coming into force in 2002, nuclear waste producers in Canada incorporated the Nuclear Waste Management Organisation with a mandate to manage and coordinate activities for the long-term management of nuclear fuel waste and also with the requirement to complete a study on the available options by 2005. In 2003 the NWMO made progress in developing its recommendations and presented its first annual report *Asking the Right Questions*. The report shows the results of a consultation being made with hundreds of Canadian groups and individuals across Canada on three potential methods for the long-term management of waste.[103] The three options being considered are: deep geological disposal in the Canadian Shield, storage at nuclear reactor sites and centralised storage either above or below ground.

RESEARCH AND DEVELOPMENT

Atomic Energy of Canada Limited (AECL), designer of the CANDU concept, is pursuing different research paths, as detailed ahead.

One is the use of slightly enriched uranium (0.9 to 1.2% in U-235) in CANDU reactors, allowing the use of less uranium and fewer bundles, in turn lowering fuel and waste management costs.[104] Cameco in 2003 made an application to the Canadian Nuclear Safety Commission (CNSC) for permission to produce slightly enriched nuclear fuel through a blending process, rather than through enrichment. The fuel is intended for use at the Bruce B Nuclear Generating Station.[105]

A path being investigated by AECL jointly with British Nuclear Fuels (BNFL) and Korea Atomic Energy Research Institute (KAERI) is the use of recovered uranium from spent fuel of light water

101 The Toronto Star (2003).

102 Bruce Power (2004).

103 CNA (2004a).

104 AECL (2004).

105 CNA (2004a).

reactors (LWR). Unburned natural uranium and slightly enriched uranium can be extracted from LWR spent fuel and later be used without re-enrichment in CANDU reactors. Double the energy can be extracted from the recovered uranium by using it in a CANDU, instead of re-enriching it as fuel for LWRs. This option also has the added advantage that it can help reduce the quantity of used fuel and the cost of storage.

The DUPIC (Direct Use of spent PWR fuel In CANDU) fuel cycle is an option involving dry-processing used fuel from pressurised water reactors (PWR) to be used directly in CANDU units. It represents a choice for economies or utilities that own both PWR and CANDU reactors, increasing the energy derived from PWR fuel by up to 50 percent. It also reduces the quantity of used fuel and aids non-proliferation by burning up plutonium.

In partnership with the United States and Russia, Canada is analysing the use of ex-weapons plutonium in mixed-oxide (MOX) fuel for CANDU plants. Plutonium mixed with natural uranium can be readily used in CANDU reactors providing a quick way to begin disposing of cold war arsenals. A small quantity of CANDU MOX fuel elements is scheduled to be tested soon in an AECL research reactor.

The use of thorium as fuel is a possibility in CANDU reactors. CANDU thorium fuel cycles range from once-through (using low-grade fuels to initiate the thorium reaction); to enriched cycles (using either enriched uranium or plutonium mixed-in with the thorium). Thorium can even lend itself to breeder reactors in which as much fissile material could be produced as is consumed.

AECL's ACR-700 and ACR-1000 are the firm's next generation reactors promising competitive pricing while at the same time offering the benefits of shorter construction schedules, reduced heavy water use, extended fuel life, and improved safety features.[106] The Advanced CANDU Reactor, or ACR in -700 and -1000 forms is an evolution of the current CANDU 6 design and is expected to have high capacity factors of around 95 percent owing to design innovations, more sophisticated operating tools and materials improvements. The ACR-700 is a 700 MW reactor while the ACR-1000 is a large 1,000 MW reactor. The new design aims at reducing the capital to build the reactor by 40 percent. If achieved, it will have the potential to be competitive with other types of power generation.[107]

One characteristic of CANDU reactors is that they can withstand a blackout event by rolling the power back to an intermediate power level of about 60 percent, rather than shutting off completely, until the grid operator is in a position to accept power again. Such is what happened with 3 operating reactors at Bruce B and one at Darlington during the August 2003 blackout, when these were the first plants in the affected area to be available for bringing back online as soon as requested by the grid operator. AECL intends to enhance this ability in the new ACR reactor designs.[108]

Over the next 25 years, the ACR will continue to evolve into a new Generation IV design that uses high temperature super critical water as a coolant. A reactor concept based on high temperature coolant is one of 6 reactor designs selected for development by experts from countries participating in the Generation IV International Forum.[109]

106 AECL (2004).

107 AECL (2004) and IAEA (2003).

108 CNA (2004a).

109 CNA (2004a).

CHINA

BACKGROUND

China is one of the 5 largest economies in the world, and with a population of 1.3 billion it houses around one-fifth of the world's inhabitants. It has sustained high rates of economic growth of around 10 percent for more than 20 years, and even though in the late 90's growth slowed slightly to about 8 percent per year, it remains high by developing nation standards. GDP per capita is still a low US$3,778 (1995 US$ at PPP) in 2001.[110]

China is the world's second largest energy consumer (next to the United States) and third largest energy producer (after the United States and Russia). China's total primary energy supply in 2001 was 790 Mtoe and its import dependency in the same year stood at 3.4 percent. China is particularly rich in coal resources, with recoverable reserves in 2001 amounting to some 114.5 billion tonnes, the third largest in the world after the United States and Russia. China is the largest producer and consumer of coal in the world. To ensure security of supply, much political and financial support has been given to the development of China's indigenous coal reserves. After 1990, however, Chinese authorities began to encourage the replacement of cleaner fuels for coal and promote energy efficiency measures to reduce emissions from energy production.[111]

China became a net oil importer in 1993 after many years of being an exporter. Its oil reserves in 2001 were of 2,910 million cubic meters. A whole one third of the crude oil and petroleum products requirements have to be imported at present. By contrast, gas production and consumption in China are still quite small. Coal and oil resources are used far more for power and industrial applications than gas or even hydraulic potential. Chinese authorities are promoting the use of gas in the building and industrial sectors as well as for power generation. China has 676 GW of technical hydropower potential, more than any country in the world.

China's substantial resources are not well distributed with respect to energy demand. Natural gas reserves are located in the western provinces of Xinjiang, Sichuan, Qinghai, Shaanxi and Gansu. Coal reserves are concentrated in the western provinces of Shanxi, Shaanxi and Inner Mongolia. Hydropower resources are mainly located in the southwest. Energy demand, on the other hand, is concentrated in the eastern provinces of Guangdong, Zhejiang, and Jiangsu, especially in the cities of Shangai, Beijing, Tianjin and other cities near the ocean.

The per capita final energy consumption in China in 2001 was 0.45 toe[112], lower than the world average but expected to increase sharply in the near future. Energy demand growth averaged 4.7 percent between 1980 and 1997, after which it experienced a significant drop and became negative for a period of 3 years resulting from the Asian financial crisis. It is now showing signs of improvement with remarkable growth values of 20 and 15 percent respectively in 2002 and 2003.[113]

The power industry in China has experienced high growth in recent decades and is also a candidate for accelerated growth in the near future. Electricity consumption grew on average 7.3 percent between 1980 and 1999.[114] In 2002 it grew 10.5 percent with respect to 2001,[115] and in the first 6 months of 2004 it increased 16 percent compared to the same period of the previous year.[116] Total installed capacity grew from 66 GW in 1980 to 353 GW by 2002. The share of nuclear energy in power generation in 2003 was 2.2 percent and is set to grow in the near- to mid-term. The

110 EWG/APERC (2003).
111 EWG/APERC (2003).
112 EWG/APERC (2003).
113 APERC (2004).
114 APERC (2002).
115 EWG/APERC (2003).
116 Xinhua (2004).

structure of the rest of China's power generation system has thermal plants (mostly coal-fired) covering around 79 percent of the total while hydropower makes up another 19 percent.[117]

The restructuring process of the electric power industry in China took firm steps in 2003 after a long period of debate and analysis. Generation and transmission have now been separated, with five generating companies having been set up based on the former State Power Corporation: China State Group Co., China Huadian Group Co., Huaneng Group Co., China Datang Group Co., and China Power Investment Co. The large hydropower companies and those power companies listed on domestic stock exchange are required to join the five companies. Besides the five power companies, there are 45 other local power generating companies, hydropower facilities, rural hydropower companies, nuclear power companies, and IPPs not involved in the restructuring. On the power transmission end two grid companies were set up: the State Power Grid Company and the South Grid Company. The State Power Grid Company is further divided into five regional grid companies: Eastern China, Central China, Northeast China, Northwest China and North China. The South Grid Company covers the region of Guangdong, Hainan, Yunnan, Guizhou and Guangxi Provinces.[118]

CURRENT SITUATION OF NUCLEAR POWER

In China, the National Development and Reform Commission (NDRC) is in charge of setting broad energy policy, energy planning at the central government level, and defining the participation of nuclear power in the electricity system. The State Commission on Science, Technology and Industry for National Defence (SCSTI) has administrative oversight on nuclear energy, and its subsidiary, the China National Atomic Energy Authority (CAEA), is responsible for managing the peaceful use of nuclear energy and promoting international cooperation. The China National Nuclear Corporation (CNNC), formerly the Ministry of Nuclear Industry and directly under the State Council, has responsibility for both civilian and military nuclear activities regarding nuclear weapons, power production, and waste disposal facilities. It also includes a significant research and development capability. Within the CNNC, the China Nuclear Energy Industry Corporation (CNEIC) is the organisation in charge of China's uranium and enrichment services. Finally the China Nuclear Engineering and Construction Group Corporation (CNEC) is the entity in charge of nuclear plant construction, nuclear engineering construction and national defence engineering construction.

Table 17 Nuclear power data summary, China

Reactors in operation	9
Nuclear installed capacity (gross)	6,988 MW
Reactors under construction	2
Total electricity generation	1,910.0 TWh
Nuclear generation	41.6 TWh
Nuclear generation share	2.2 %

Note: Generation figures for 2003.
Source: IAEA (2004).

China's civilian nuclear programme was built on the heels of a long history of military nuclear achievements that started after the establishment of the People's Republic of China in 1949 and that gave as a result the development of both atomic and hydrogen weapons in 1964 and 1967 respectively and the commissioning of the first of several nuclear-powered submarines in 1971.

[117] EWG/APERC (2003).
[118] EWG/APERC (2003).

China has up to now focused its nuclear power plant technology on pressurised water reactors (PWR), mostly of the enriched uranium-light water kind, but also including 2 Canadian designed heavy water reactors that operate on natural uranium with no requirement for enrichment. A relatively good industry basis has been established for pressurised water reactor technologies including design, construction and operation, as well as fuel design and manufacture. China basically has the technical ability to build PWR plants by itself. In addition to that it has a continuing programme for the development of its own advanced PWR technology. Through international collaboration China intends to identify state of the art technology for further advancement and large-scale application into indigenous reactor designs for the future.

The civilian programme for nuclear power generation started with the indigenous design and construction of a prototype 300 MW pressurised water reactor (PWR) using a pressure vessel supplied by Mitsubishi Heavy Industries of Japan. Construction of the plant started at Qinshan 100 km southwest of Shangai in 1985 and entered commercial operation in May 1994. Later to be dubbed Qinshan 1, the reactor was shut down 14 months in mid 1998 for major repairs and has since been brought back online.[119]

A different path was followed for the reactors at Daya Bay near Hong Kong, where instead of opting for an in-house design, two standard French PWR units of 984 MW each supplied by Framatome were constructed by Electricite de France (EDF) with participation of Chinese engineers. Seventy percent of the power produced by these reactors is transmitted to Hong Kong while 30 percent is delivered to Guangdong. Between 1994 and 1996 the plant underwent long outages for the replacement of major components by Framatome. Lingao units 1 and 2 of 990 MW each, also situated in Guangdong, are similar PWR units supplied by Framatome ANP that started operating in February and September of 2002 respectively.[120]

Table 18 Nuclear power reactors in operation and under construction in China

Name	Technology and vendor economy	Location	Gross Capacity (MWe)	Commercial Operation
Operational				
Qinshan 1	PWR, China	Zhejiang	300	Apr. 1994
Qinshan 2, unit 1	PWR, China	Zhejiang	642	Apr. 2002
Qinshan 2, unit 2	PWR, China	Zhejiang	642	May 2004
Qinshan 3, unit 1	PHWR, Canada	Zhejiang	728	Dec. 2002
Qinshan 3, unit 2	PHWR, Canada	Zhejiang	728	Jul. 2003
Daya Bay unit 1	PWR, France	Guangdong	984	Feb. 1994
Daya Bay unit 2	PWR, France	Guangdong	984	May 1994
Lingao unit 1	PWR, France	Guangdong	990	May 2002
Lingao unit 2	PWR, France	Guangdong	990	Jan. 2003
Under construction				
Tianwan (Lianyungang) unit 1	VVER, Russia	Jiangsu	1,060	2005
Tianwan (Lianyungang) unit 2	VVER, Russia	Jiangsu	1,060	2005

Source: Tsinghua University (2003), IAEA PRIS 2004.

Qinshan phase 2, units 1 and 2 are the other only Chinese designed and constructed reactors in China. These 642 MW PWRs are scaled up versions of Qinshan 1. Qinshan 2, Unit 1 started commercial operation in April 2002 and unit 2 just finished construction and began commercial operation in May, 2004.[121]

119 IEEJ (2003b), WNA (2003a).

120 WNA (2003a).

121 IAEA (2004a).

Units 1 and 2 of Qinshan phase 3 are 728 MW CANDU type reactors of Canadian design provided on a turnkey basis by Atomic Energy of Canada Limited (AECL). Construction began in 1997 and commercial operation started in 2002 for unit 1 and 2003 for unit 2.

At present two other reactors are under construction at Tianwan (Lianyungang) in Jiangsu under a cooperation agreement between Russia and China. The 1,060 MW reactors are of the Russian VVER-91 type with upgraded safety systems, instrumentation and control equipment, and should be operational in one or two more years.

Table 18 shows the list of reactors operating and under construction in China. Total capacity from these reactors amounts to 9,108 MW, of which 6,988 MW are operational and 2,120 MW are under construction.

Figure 23 Location of nuclear power plants in China

Source: Perry-Castañeda Library Map Collection.

As a result of its military nuclear activities, China has capabilities in most all phases of the nuclear fuel cycle. These include uranium exploration and mining, enrichment, fuel element fabrication, temporary spent fuel storage and reprocessing.

At present uranium enrichment is done both within China and externally through a contract with Urenco in Europe. Domestic enrichment for civilian purposes is performed in at least 3 places:

Chengdu in central Sichuan Province, Lanzhou in Gansu Province and Hanzhong on the Han Shui river in southern Shaanxi Province. In Chengdu, a Russian built plant of the centrifuge type with a capacity of 200,000 separative work units/year (SWU/yr) has been in operation since 1997 and has produced uranium for the Qinshan plant. Lanzhou houses a facility also of Russian technology originally used for military purposes with a present capacity of 900,000 SWU/yr using the gaseous diffusion type process. The plant has been in operation since 1980 but it is considered to be inefficient according to Chinese officials and will eventually be shut down to be replaced with a centrifuge type plant with a capacity of 500,000 SWU/yr that will be operational in 2005. Another unit of the same capacity is expected to join it afterwards.[122]

Two modules totalling a fuel enrichment capacity of 500,000 SWU/yr were constructed in Hanzhong in southern Shaanxi, and are now operational according to the Government. In total, it is expected that China will have 1.5 million SWU/yr capacity of enrichment by the year 2005 for civilian purposes. There is at least another facility that was used for military purposes in Heping, Sichuan province, but according to the China Nuclear Energy Industry Corp., military production of highly enriched uranium has stopped since 1980 in China.[123] The new machines constructed in Hanzhong and the ones under construction in Lanzhou, are part of an agreement with Russia in which this economy would install the equipment in China to be operated under safeguards by the International Atomic Energy Agency.[124]

Fabrication of PWR fuel is being done at a plant at Yibin in Sichuan Province for the Qinshan and Daya Bay nuclear plants. Another plant at Baotou City in Inner Mongolia will provide PHWR fuel to the CANDU type plants in the future.[125]

China is committed to a fuel cycle featuring the reprocessing of spent fuel. Its spent fuel activities therefore include at-reactor storage, away from reactor storage, and reprocessing. A centralised spent fuel storage facility with a capacity of 550 tonnes of fuel has been in operation since 2000 at Lanzhou Nuclear Fuel Complex in Gansu Province. Its capacity could be extended to 500 additional tonnes.

Two pilot plants for reprocessing of spent fuel are now being decommissioned in Lanzhou and in the Gobi Desert in Gansu Province. A new fuel reprocessing pilot plant is under construction in Lanzhou with cold commissioning[126] expected in 2002, and a commercial scale reprocessing plant with a capacity of 800 tonnes of heavy metal/year is planned to start operations in the year 2020.[127]

CHINA'S NUCLEAR POWER POLICY

China's *Tenth Five-Year Plan* (2001-2005) incorporates nuclear energy as a part of China's strategy to guarantee energy security, one of its major goals. The Plan calls for a policy that includes a *moderate development of nuclear power generation* in order to fulfil domestic electricity consumption. China's recent industrial growth following its entry into the World Trade Organisation has accelerated its demand for electricity. Limitations and shortages in the electricity supply system, however, are having a negative impact on further growth. The nationwide shortage of power estimated by Chinese officials exceeded 20,000 MW in 2004.[128] In June, July and August of the same year, the hot summer brought along with it rolling power outages around the nation and widespread factory shutdowns. Power shortages caused blackouts in Shangai and Beijing and affected 24 of the nation's 27 provinces and municipalities.[129] Uneven geographical distribution of resources limits the available economical options in some areas. Coal, the main source of electricity generation is mainly produced in western provinces and hydropower is mostly found in the southwest; while power consumption is concentrated in the coastal regions of the east and south. Coal transportation over long distances

[122] IAEA (2004b).
[123] IAEA (2004b).
[124] IAEA(2004b).
[125] WNA (2003a).
[126] Tests with non-radioactive material.
[127] WNA (2003a) and IAEA (2004b).
[128] Xinhua (2004).
[129] Bloomberg (2004).

impacts its price by a large factor, as in China the cost of transport is a major component. On the other hand the impact of hydro projects of the scale of Three Gorges on population and arable land precludes many more such projects for being socially expensive and unsustainable to an extent. It is therefore natural according to nuclear industry officials to pursue the development of nuclear power for a more balanced development of the national economy and to protect the environment.[130]

According to the Institute of Nuclear Energy Technology at Tsinghua University, nuclear energy is also being understood as the only technical option that can substitute for fossil fuels to produce base-load power on a large scale. Large-scale nuclear power generation can help ease the pressures of meeting capacity demand while improving the energy structure and reducing the effects of resource shortages and uneven distribution. Diversifying the sources of electricity generation and specifically lessening the dependence on coal places nuclear energy in an important position in the quest for the consolidation of energy security. It is also a significant contributor to environmental protection and the reduction of greenhouse gas emissions.[131]

Another aspect of the nuclear policy in China is the drive to incorporate as much local engineering content as possible in the design and in all phases of the nuclear power production chain. The Tenth Five-Year Plan sets the target of achieving domestic production of nuclear power generation equipment. In addition, it calls for active support for the development of new advanced reactors that are unique to China, and laying the foundation for nuclear power development in subsequent Five-Year Plan periods. According to the CNNC, it is impractical to rely on importing complete plants and services for a large-scale nuclear development programme such as China's. Increasing local content is seen as a tool to help reduce construction and maintenance costs, improve operational safety and enhance the competitiveness of nuclear power.[132]

One area in which China aspires to be self-sufficient is nuclear fuel supply. Present capacity is limited and therefore to meet such goal more fuel fabrication capacity will have to be built in the near future.

As explained before, China is committed to a fuel cycle with spent fuel reprocessing, which is seen as necessary to make a more efficient use of its limited uranium resources and to minimise nuclear wastes. This strategy is concurrent with the plan to develop and implement fast breeder reactors, the kind that breed more nuclear material than it consumes, and which require reprocessing of the out-coming fuel to retrieve the unburned fuel plus the newly produced fuel material. While China is at present focusing on the uranium-plutonium reprocessing fuel cycle, an interest exists also on the thorium-uranium fuel cycle for the long term, given that China possesses considerable resources of thorium.

To enhance nuclear safety, China has pursued reactor designs that have proven to have good safety records worldwide. The Chinese nuclear safety authority has formulated new requirement policies with regard to the safety of future nuclear power plants. The essence of the new requirements is to enhance nuclear safety of plants starting at the plant design stage. The main focus is on reducing the likelihood of reactor core damage and the probability of radioactivity releases into the environment.

FUTURE PLANS

Plans for future expansion of nuclear capacity have been drawn in previous years by the State Development and Planning Commission (now the National Development and Reform Commission) and the China National Atomic Energy Authority following the guidelines of the Tenth Five-Year Plan, which in itself does not include specific targets. After several adjustments to these somewhat optimistic projections, the government announced in 2003 a plan that has served as the basis for the official agenda on new nuclear power plant approvals and construction. This latest version calls for China's nuclear plants to provide 4 percent of its total power supply by the year 2020, up from 2.2

[130] Xinhua (2004).

[131] Tsinghua University (2003).

[132] Xinhua (2004).

percent today. This is equivalent to 36,000 MW of installed nuclear generating capacity by 2020, or five times today's capacity of 7,000 MW,[133] and would require the construction of two 1,000 MW plants every year from 2004 up to 2020. Other statements by nuclear government officials point to the relatively low share of nuclear power in China's total power production as compared to its share of 17 percent in world power production at present, a sort of implied suggestion that China could aim towards the world average in the long run.

Commensurate with this plan of constructing 2 reactors every year, the CNNC has submitted for government approval 4 new nuclear projects that consist of 2 reactors each. Of these, approval has already been obtained for two new 600 MW reactors in addition to those already existing at Qinshan in Zhejiang, two more 1,000 MW reactors at Lingao in Guangdong, and two 1,000 MW units at Sanmen also in Zhejiang.[134]

Table 19 Nuclear power reactors planned in China, as of 2004

Name	Technology and Vendor economy	Location	Gross Capacity (MWe)	Commercial Operation
Approved for construction				
Qinshan 4, unit 1	PHWR, Canada	Zhejiang	600	2010
Qinshan 4, unit 2	PHWR, Canada	Zhejiang	600	2010
Lingao 2, unit 1	PWR, France	Guangdong	1,000	2010
Lingao 2 , unit 2	PWR, France	Guangdong	1,000	2010
Sanmen unit 1		Zhejiang	1,000	
Sanmen unit 2		Zhejiang	1,000	
Under consideration				
Yangjiang unit 1		Guangdong	1,000	
Yangjiang unit 2		Guangdong	1,000	
Haiyang unit 1		Shandong	1,000	
Sanmen unit 3		Zhejiang	1,000	
Sanmen unit 4		Zhejiang	1,000	
Sanmen unit 5		Zhejiang	1,000	
Sanmen unit 6		Zhejiang	1,000	
Haiyang unit2		Shandong	1,000	
Hui An unit 1		Fujian	1,000	
Hui An unit 2		Fujian	1,000	
Tianwan 2, unit 1		Jiangsu	1,000	
Tianwan 2, unit 2		Jiangsu	1,000	
Yangjiang 2, unit 1		Guangdong	1,000	
Yangjiang 2, unit 2		Guangdong	1,000	
Yangjiang 3, unit 1		Guangdong	1,000	
Yangjiang 3, unit 2		Guangdong	1,000	
Jinzhouwan, unit 1		Liaoning	1,000	
Jinzhouwan, unit 2		Liaoning	1,000	
Jiujiang, unit 1		Jiangxi	300	
Jiujiang, unit 2		Jiangxi	300	
Hainan, unit 1		Hainan	300	
Hainan, unit 2		Hainan	300	
Fuling Baitaozheng, unit 1		Chongqing	900	
Fuling Baitaozheng, unit 2		Chongqing	900	

Source: IEEJ (2003b), Energy Central (2004a).

133 The Japan Times (2004).

134 Energy Central (2004a).

The proposed project for Sanmen includes the construction of a total of six 1,000 MW reactors, but only two will be constructed in the first phase. CNNC continues lobbying the government to obtain approval for two 1,000 MW units at Yangjiang in Guangdong and a second phase of 2 more units of 1,000 MW each for Sanmen. The design for the units at Qinshan and Lingao have been fixed to be the same as the previous plants at the same sites. For Sanmen, however, as of July 2004 the CNNC was preparing to invite international tenders for the design, equipment supply and construction of the first phase. Areva from France and Westinghouse from Pittsburgh (now a BNFL company) are competing for the project. Table 19 shows a list of all units that have been proposed as of 2004 in several provinces of China.

Some studies in China project as much as 50 GW by the year 2030 and somewhere between 120 and 240 GW by the year 2050 to be able to cope with the expected demands. By that year, it is expected that a major share of the nuclear installed capacity will consist of new fourth generation domestic designs such as the pebble-bed modular high-temperature gas-cooled reactor (HTGR) being under development in China.

An ever-present risk in the present situation is that of moving towards a surplus of power in the years ahead. During a period of power shortages the approval of new projects is expedited and there is a tendency to build excess capacity. IPP investors in China already lived through the experience of having to lower price agreements in a poor bargaining position against power-rich provinces in the late 1990s. Foreign investment in the power industry as a whole might be limited in view of the threat of possible excess capacities in the near future and its impact on the return of investments.

RESEARCH AND DEVELOPMENT

In view of the massive development expected of China's nuclear industry in the future, the Chinese government believes it is in their best interest to develop domestic capabilities in all areas of nuclear technology including the construction of facilities and the provision of nuclear services. Much has been accomplished already through international collaboration in research projects and through joint partnerships in the construction of nuclear power plants. According to the Institute of Nuclear Energy Technology, China basically has the technical capability to build PWR plants by itself. At the moment a goal of the nuclear industry in China is to increase the level of domestic content in all nuclear power equipment from 50 percent in 2003 to 70 percent in the following 3-4 years.

In the area of reactor design, China has gained much experience in pressurised light water reactor (PWR) technology and is working in the development of advanced PWR designs, such as the CNP-1000. Being developed by the CNNC, this reactor is intended to meet Chinese safety requirements and foster local equipment manufacture to reduce construction and operating costs. It will incorporate lessons learned during the design and construction of the Qinshan 2 and Daya Bay plants. Another, smaller PWR reactor with 200 MWth was developed by the Institute for Nuclear Energy Technology at Tsinghua University for water desalination and district heat.[135]

China and South Africa are today leaders in the development of high temperature gas-cooled reactors (HTGR) of the pebble-bed modular type with both economies having backing from the government and involved in important international cooperation efforts. China is also the only other economy besides Japan to operate an experimental unit. A 10 MWth high-temperature gas-cooled demonstration reactor with compacted uranium-graphite fuel spheres (or pebbles) started full-power operation in 2003 at Tsinghua University. China and South Africa both have plans to build larger, 160 MW demonstration modular reactors by 2010 with a view to commercialise the technology for standardised large-scale manufacture in the future.[136] Modular pebble-bed HTGRs could be easily and economically deployed as needed to satisfy demand in high demand areas. As well, the high outlet temperatures of HTGRs allow them to serve double duty as sources of process heat for heavy oil recovery, coal gasification or hydrogen production using thermo-chemical methods.

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135 IAEA (2003).

136 AFP (2004).

China is also involved in fast breeder reactor research. A 65 MWth (25 MWe) sodium-cooled fast neutron reactor called the Chinese Experimental Fast Reactor (CEFR) is under construction and expected to be operational in 2005. It will be used to gain experience with fast reactor operation and to conduct experimental and safety demonstration testing.

In the area of fuel cycle operations, most of the Chinese research and development in uranium enrichment has been in the area of gaseous diffusion. Now China is cooperating with Russia on design and engineering of the more advanced centrifuge process for uranium enrichment. In addition to its cooperation with Russia, China has advanced in the indigenous development of sub-critical centrifuges and is active in the research of the laser enrichment process.[137]

[137] IAEA (2004b).

CHINESE TAIPEI

BACKGROUND

Chinese Taipei 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 annually between 1980 and 1995 that slowed down after the Asian financial crisis of 1997. The lowest point came in the recession of 2001, which resulted in a negative growth of –2.2 percent prompted by a low demand for consumer electronic products. However the economy seems to have recovered attaining in 2002 a real GDP growth of 3.5 percent relative to the previous year and showing signs of maintaining growth with a projected expansion of 3.8 percent for 2003. Its GDP per capita in 2001 stood at US$ 14,844 (1995 US$ at PPP).[138]

Chinese Taipei has very limited domestic energy resources and relies by as much as 87 percent on imports for its energy needs. Total primary energy supply in 2001 was 85 Mtoe and per capita energy consumption was 2.4 toe.[139]

Electricity demand annual growth rate between 1980 and 1999 averaged 7.5 percent.[140] Nuclear power in 2003 accounted for 21.5 percent of total electricity generation. The other components in the power generation structure are thermal plants, which account for 75 percent and hydropower plants that represent the other 4 percent.[141]

The electricity system in Chinese Taipei is likely to undergo a privatisation process in the near future. The push for privatisation appears to be the result of rapidly growing demand, and the state utility Taipower's inability to finance the necessary additional generation capacity required, which already created a crisis during the summer peak demand months in 1999. A new electricity law is being discussed in Parliament that will define the economy's position on the issue of the privatisation of Taipower's generation assets.

CURRENT SITUATION OF NUCLEAR POWER

Taipower is Chinese Taipei's state-owned power utility. IPPs are allowed in Chinese Taipei since 1994 and together with cogenerators they produce 22 percent of the total power generation in the island. The control over nuclear and hydro plants is maintained by Taipower. Chinese Taipei currently has 6 reactors in operation in 3 plants, which have been in commercial operation since between 1977 and 1985. The nuclear installed capacity totals 5,144 MW and it accounted for 16 percent of the total in 2002.

There are two reactors under construction in one plant at Lungmen, referred to as the fourth nuclear power plant scheduled for commercial operation in 2006 and 2007 respectively. The units are of the General Electric advanced boiling water reactor (ABWR) type and will have a capacity of 1,350 MW each.

The project was the source of much controversy especially after the inauguration of the present Democratic Progressive Party (DPP) Government and its pledge for a nuclear free homeland in May of 2000. An order for the cancellation of the plant's construction in October 2002 was later overturned by a ruling of the Council of Grand Justice based on the unconstitutionality of the decision. After negotiations between the Executive and Legislative branches, it was agreed to resume the plant's construction in February of 2001. The Government has since vowed not to support the construction of additional nuclear plants in the future, although this decision might be strongly dependent on the political party in power at the time.

[138] EWG/APERC (2003).

[139] EWG/APERC (2003).

[140] APERC (2002).

[141] TAIPOWER (2004).

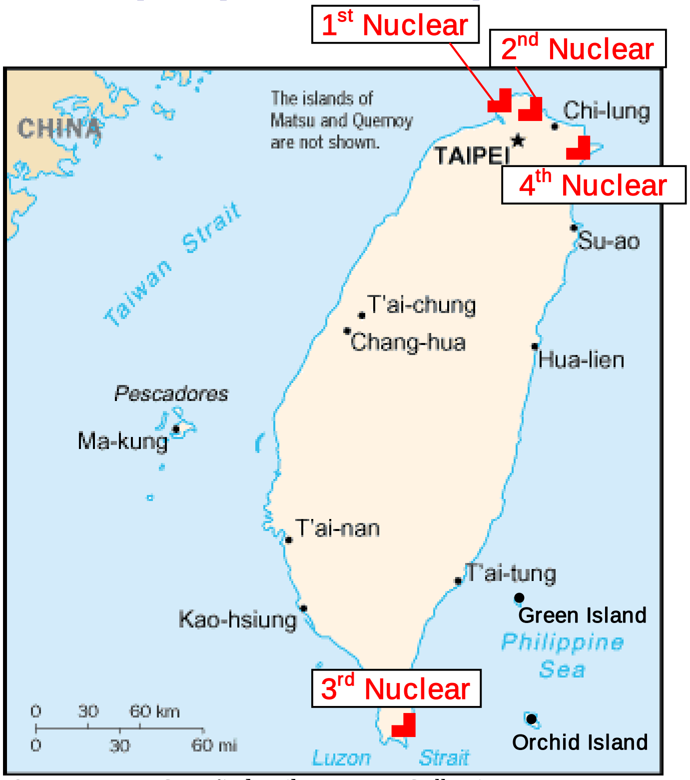
Table 20 Nuclear power data summary, Chinese Taipei

Reactors in operation	6
Nuclear installed capacity (gross)	5,144 MW
Reactors under construction	2
Total electricity generation	173.8 TWh
Nuclear generation	37.4 TWh
Nuclear generation share	21.5 %

Note: Generation figures are for 2003.
Source: TAIPOWER (2004), IAEA (2004).

The original pledge of the DPP Government was to have only LNG plants approved for the expansion of the electricity system, increasing this fuel's participation in the total fuel mix to about one-third by 2010. Recently, however, this policy of having natural gas as the fuel of choice is being questioned due to rising costs. This could signal the need to construct more coal-fired plants in the future, after a period of purposefully limiting the growth of coal's participation.

Figure 24 Location of nuclear power plants in Chinese Taipei



Source: Perry-Castañeda Library Map Collection.

With land acquisition being a problem in the already space-limited island of Chinese Taipei and also the difficulty regarding public opinion in selecting a site for permanent disposal, the Atomic Energy Council is looking into laser driven transmutation technology to process its spent fuel high-level radioactive waste. As will be seen later, transmutation is a technique that involves bombarding radioactive elements at high energies to convert them into isotopes with shorter radioactive half-lives. The Council expects this technology to be an efficient, economical and safe way to handle radioactive waste.

Roughly 98,000 barrels of low-level nuclear waste is being stored on Orchid Island. The Ministry of Economic Affairs has not yet reached a decision over whether to relocate the waste abroad or elsewhere to another domestic site. A decision is expected soon and the Atomic Energy Council expects to have the relocation project completed by 2008. Funding for the project, estimated at US$ 900 million, would come from the economy's US$ 9 billion nuclear handling fund.[142]

Table 21 Nuclear power reactors in operation and under construction in Chinese Taipei

Name	Type	Gross Capacity (MWe)	Date Connected
Operational			
Chin Shan-1	BWR	636	11/16/1977
Chin Shan-2	BWR	636	12/19/1978
Kuosheng-1	BWR	985	5/21/1981
Kuosheng-2	BWR	985	6/29/1982
Maanshan-1	PWR	951	5/9/1984
Maanshan-2	PWR	951	2/25/1985
Under construction			
Lung Mei 1	ABWR	1,350	1/16/2006
Lung Mei 2	ABWR	1,350	1/16/2007

Source: IAEA (2004a).

142 The Taipei Times (2004).

MEXICO

BACKGROUND

Mexico's per capita income in 2001 was US$ 8,125 (1995 US$ at PPP). The average real GDP growth rate in Mexico between 1980 and 1995 was a low 1.7 percent tempered by episodes of economic decline in the years 1982, 1988 and 1995.[143] A pattern of growth at an average rate of 5.5 percent was established between 1995 and 2000 only to be interrupted again with a contraction of –0.2 percent in 2002 when United States, Mexico's largest commercial trade partner, experienced a downturn. Growth was regained in 2002 at a rate of 0.7 percent and it increased to 1.3 percent for 2003.[144] Expectations are for the economy to stabilise at faster growth numbers of around 5 percent in the near future.

Total primary energy supply in 2001 was 151 Mtoe. Per capita energy consumption in the same year was 0.9 toe. Proven oil reserves in Mexico in 2003 were the world's 13th largest. Mexico's PEMEX is the sixth largest oil company in the world in terms of revenue, exporting around 55 percent of the crude it produces. These export sales play a crucial role in Mexico's economy accounting for as much as one third of Government revenue.[145]

Mexico also has large reserves of gas, even if production in 2002 was low at 4.4 billion cubic feet per day.[146] Although small quantities are exported to the United States at different points in the common border, Mexico depends on net imports to meet the totality of its domestic needs. Scarcity of investment funds has precluded building the necessary infrastructure to produce enough natural gas for internal demand and for export.

Despite the unevenness in economic growth, Mexico has experienced strong growth in electricity demand in the previous decades. Between 1980 and 1999 electricity demand growth averaged an annual rate of 5.4 percent, and reached 7.1 percent in 2000 as compared to the previous year.[147] The effect of the economic slowdown made electricity demand growths stumble in 2001 and 2002 to values of 1.2 and 1.9 percent respectively, but as the economy improves and industrialisation continues, it is expected to show high growths again soon. As much as 5.2 percent of power generation in Mexico comes from nuclear power. Fuel oil fired plants contribute with 43 percent, natural gas plants with 22 percent, hydropower with 12 percent, coal with 15 percent and geothermal and wind with the remainder.[148]

CURRENT SITUATION OF NUCLEAR POWER

Mexico has two General Electric BWR-type nuclear power reactors at the Laguna Verde plant site on the Gulf of Mexico coast; the first unit starting commercial operation in 1990 and the second in 1995. The reactors, which are owned by the State's national electricity utility Comisión Federal de Electricidad (CFE), were uprated to 105 percent of their original power in July 1999 and they now have a combined total capacity of 1,364 MW. Performance indicators have been high so far for these two units, both consistently operating for periods of more than 300 days without unplanned interruptions. The total average capacity factor of the two units stands at 81 percent since the beginning of operation and up to 2003.[149]

143 EWG/APERC (2003).
144 INEGI (2004).
145 EWG/APERC (2003).
146 EWG/APERC (2003).
147 APERC (2002).
148 SENER (2003b).
149 CFE (2003).

Table 22 Nuclear power data summary, Mexico

Reactors in operation	2
Nuclear installed capacity (gross)	1,364 MW
Reactors under construction	0
Total electricity generation	200.9 TWh
Nuclear generation	10.5 TWh
Nuclear generation share	5.2 %

Note: Generation figures are for 2003.
Source: SENER (2003b), IAEA (2004).

Although enough uranium resources are known to exist to fuel both reactors through their lifetimes, there is no local production at the moment and uranium is procured from the international market, where low prices continue to favour importation. Enrichment and fuel fabrication is contracted externally, although Mexico has developed fuel fabrication technology locally. A fuel fabrication pilot plant was installed at the National Institute for Nuclear Research that produced prototype fuel assemblies for the nuclear plant in 1995. However, because no other reactors have been built, and due to surplus capacity in the international market holding fuel fabrication prices down, it was considered not economical to continue fabrication at a larger scale for the time being.

Figure 25 Location of the nuclear power plant in Mexico

Source: Perry-Castañeda Library Map Collection.

The plant has a low and intermediate level nuclear waste facility within the site itself with enough capacity to dispose of the waste generated by the plant during its lifetime. Spent fuel assemblies are stored inside the plant in fuel pools that have been re-conditioned to add enough capacity to also hold all the fuel needed during the life of the plant's two units.

MEXICO'S NUCLEAR POWER POLICY

Mexico's electricity system depends on fuel oil and diesel for 43 percent of its total power production and actions are being taken to turn around this trend. Options for diversifying the fuels used in generation are neither obvious nor easy in Mexico. In the last 10 years, Mexico has moved away from fuel-oil fired plants in favour of natural gas combined cycles both for economical as well as for environmental reasons. The participation of natural gas in power generation has almost quadrupled in those 10 years, going from 6 percent in 1992 to 22 percent in 2002, while that of oil products has changed from 58 percent to the present 43 percent.[150] The Mexican Ministry of Energy's latest electricity expansion plan for the period 2003-2012[151] calls for the construction of close to 28,000 MW of new generation capacity during the period, of which 40 percent will be fuelled by natural gas, 10 percent will be hydropower plants and as much as 44 percent is yet to be decided. This last 44 percent fraction corresponds to the additional capacity that the national power utility anticipates to tender out to private investors as IPP projects and it is expected that more than half of it will be also fuelled by natural gas. This would make this last fuel the basis for at least 63 percent of all new capacity to be built in the period. However investment limitations mentioned earlier preclude development of Mexico's vast natural gas resources, meaning that at least for the medium term the demand will have to be met with imports. Plans are underway for the construction of several LNG terminals for gas imports to help in meeting electricity and industrial gas demand in the future. CFE has recently awarded a contract to Royal Dutch Shell for the supply of natural gas to be imported as LNG to a terminal and storage facility in Altamira, on the Gulf of Mexico Coast. Additionally, three more LNG terminal and storage projects have been granted permits by the national regulatory commission for plants to be built on the Pacific coast.

Table 23 Nuclear power reactors in operation in Mexico

Name	Type	Location	Gross Capacity (MWe)	Date Connected
Laguna Verde-1	BWR	Veracruz	682	4/13/1989
Laguna Verde-2	BWR	Veracruz	682	11/11/1994

Source: IAEA (2004a)

Seventy percent of Mexico's coal reserves are of the coking kind, and only 30 percent are of the thermal type used to fuel coal power plants. Forty eight percent of the total coal primary supply in Mexico is imported.[152] According to the Energy Ministry's National Energy Balance 2002, demand for coal by coal power plants is larger than domestic production, to the point where coking coal and imports are generally needed to satisfy the demand from the power plants. Three coal power plants operate in Mexico as of December 2003; two consuming domestic coal and the other using imported coal since 1999. There are enough coal reserves for the operation of a 2,100 MW power plant for a period of 100 years, but the construction of more than one coal power plant will require more imports. An invitation for tenders has been issued for the construction of a new plant, Petacalco II, to be operational by 2008. Coal supplies are abundant worldwide at low prices and are expected to remain that way, however, the elevated cost of modern emission control equipment and environmental restrictions introduce some uncertainty to the cost of coal generated electricity in the future. Depending on the price of fuels at a particular time, the total cost of electricity over the lifetime of a coal plant with modern emission control equipment can be anywhere from 0.8 to 1.0 US cents per kWh higher than that of a combined cycle natural gas plant. Coal unavailability and un-developed natural gas resources means that generation will be based on imported fuels in the next 10 to 20 years.

Mexico includes nuclear reactors in its list of typical projects to be considered as possible options in its yearly analysis of electrical system expansion, however at present no plans exist for the construction of more nuclear power plants. The Energy Ministry cites reasons of poor economics as compared to combined cycle natural gas or clean coal plants.

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150 SENER (2003b).

151 SENER (2003b).

152 SENER (2003a).

Waste disposal activities are the responsibility of the Ministry of Energy according to law. The policy on high-level waste management has been one of wait and see. Mexico expects to benefit from observing the experience of others in testing and actual operation of waste facilities that are sure to come on line in the short to mid-term future. At present, spent fuel is being stored temporarily in the reactor building fuel pools. The fuel will eventually be transferred to temporary storage and to final disposal facilities, once a decision to construct such facilities is made. No plans exist for reprocessing nor for the use of MOX fuel.

AN EXCEPTIONAL CASE: INDIA

India, not a member economy of the APEC organisation, is an interesting case in nuclear power plant development. It has 14 reactors in operation totalling 2,770 MW, and contributing 3.3 percent to the total electricity production. It has a further 8 reactors under construction with a total capacity of 3,960 MW.[153]

India also has impressive plans for nuclear expansion. Under its 3 Stage Plan a total of about 25 additional reactors are planned between the years 2010 and 2020, which would increase the total installed nuclear capacity in India to around 20,000 MW and would represent a 25 percent share in total electricity production in that year. India's nuclear industry development has been largely indigenous due to restrictions imposed on the nation internationally for procuring nuclear weapons. India is also pursuing the development of the thorium fuel cycle using fast breeder reactors to breed uranium 233 from thorium and have the ability to utilise its large thorium resources.[154] India has been estimated to have one fourth of the world's reserves of thorium.[155]

POLICIES IN NON-NUCLEAR ECONOMIES

Following is a brief summary of the power generation status and policy on nuclear power, if any, in a selection of APEC economies that do not have commercial nuclear reactors at present.

AUSTRALIA

Australia is an economy of 19.2 million people, with a per capita GDP income in 2001 of around US$24,084 (1995 US$ at PPP).

The Australian economy is well endowed with natural resources. Currently, it is the world's second largest producer of uranium behind Canada, the largest exporter of uranium, with a share of around 28 percent, the largest exporter of coal and the third largest exporter of LNG. Australia imports around 30 percent of its oil requirements although this figure has been as low as 16 percent in recent years (in 2001). APERC projects oil import dependency to increase to around 46 percent in 2020. Australia has recently averaged over 7,900 tonnes of uranium exports per year.[156] Projections are for annual production of 10,180 tonnes between now and 2015.[157] Economic reserves are estimated at around 120 years based on this production level.[158]

The Australian power system comprises around 44,000 MW (2001). Total annual generation is around 210 TWh. Due to abundant coal reserves, Australia is one of the economies in APEC and the world with the highest reliance on coal for electricity generation, higher than any other economy in APEC. In 2003, 78 percent of generation was from coal, around 13 percent from natural gas, 8

[153] IAEA (2004a).
[154] WNA (2004c).
[155] American Scientist (2003).
[156] WNA (2004e).
[157] ABARE (1999).
[158] Ibid, p60.

percent from hydro with small amounts of generation from oil and non-hydro renewables.[159] The Australian Bureau of Agricultural and Resource Economics (ABARE) projects electricity generation to grow by an average of 2.3 percent per annum to 2019-20, with coal's share falling to around 70 percent and natural gas' share increasing to almost 20 percent. Although wind power is projected to grow by 25.2 percent per annum, its share in 2019-20 is projected to be of only 1 percent.

Abundant supplies of coal and natural gas mean that Australia has a comparative advantage as far as electricity generation economics are concerned. The reserves-to-production ratios for gas and coal are 74 years and 243 years, respectively.[160] New coal generation is projected to be available at just over 3 (Australian) c/kWh and natural gas at 3.3 c/kWh. Final consumer prices are, consequently, also quite low by industrialised world standards.

Given the above, electricity generation by nuclear means in Australia would at first glance seem uneconomical. However, CO_2 emissions coming from a high share of electricity generated using coal remains a pressing concern. Policies to stabilise the level of emissions in Australia in the future might include emissions trading or carbon taxes which could make nuclear power competitive against coal or natural gas. Coal in electricity and heat generation accounts for 172 million tonnes of carbon dioxide per year. Australia in 2001 produced 1.5 percent of the world's total energy-related carbon emissions and according to the Australian Institute, an independent public policy research centre, Australia has the highest per capita carbon emissions of the industrialised world if total greenhouse gas emissions are accounted for including those associated with agriculture.[161] One quarter, or approximately 8,000 MW of Australia's thermal generating capacity will need to be replaced in the next 15 years. A reduction of about 25-30 million tonnes of CO_2 emissions per year could be attained if this were to be replaced by gas-fired plants, and a reduction of about 50 million tonnes of CO_2 emissions per year could be achieved if it were to be replaced by 6 to 8 nuclear reactors.[162] No nuclear plants are included in ABARE's projections.[163]

Australia has had a nuclear reactor for materials testing in operation since 1958. Being the largest uranium exporter in the world and second largest uranium producer, for a while there was a research programme on uranium enrichment for export purposes.

Legislation enacted years ago in two states in Australia prohibits the construction and operation of nuclear reactors. Such is the case of the Nuclear Activities (Prohibitions) Act 1983 of the state of Victoria, and the Uranium Mining and Nuclear Facilities (Prohibitions) Act 1986 of New South Wales.[164]

CHILE

Chile is inhabited by 15 million people and has a GDP per capita of US$ 8,669 (1995 US$ at PPP). Chile has limited energy resources and relies on imports for 56 percent of its total primary energy supply.

The electricity system in Chile generated 42 TWh in 2001 with a full one half of it coming from hydro plants and the rest from thermal plants. Natural gas (60 percent), coal (34 percent) and oil and biomass make up the thermal portion of the power system.

The risk of Chile's high dependence on hydro power was evident in the drought of 1998-1999 when massive blackouts affected the economy. Since then the focus has turned to building a stronger base of gas-fired plants and the procurement of natural gas from foreign suppliers. This strategy however also backfired in 2002 when Argentina, faced with domestic demand difficulties, forfeited supply contracts with Chile causing it an unexpected energy crisis. New restrictions were imposed

159 WNA (2004f).
160 BP (2003).
161 EIA (2003a).
162 WNA (2004f).
163 ABARE (2001).
164 WNA (2004f).

again by Argentina on natural gas deliveries to Chile as recently as April 2004, causing a new round of blackouts.

Chile has 2 research reactors in operation.

HONG KONG, CHINA

Hong Kong is a city-state populated by some 6.7 million people and it has a per capita GDP of US$ 24,016 (1995 US$ at PPP). The service sector is responsible for 85 percent of the GDP. Hong Kong has no domestic energy reserves nor petroleum refineries and imports all of its primary energy needs, although it generates some electricity. In 1995 Hong Kong started importing natural gas by pipeline from the Yacheng offshore field.

Hong Kong had a total installed generating capacity of 12,200 MW in 2002, owned by its two electric companies: CLP Power Hong Kong Limited (CLP Power) and The Hong Kong Electric Company Limited (HEC). CLP Power imports electricity from China: it has contracted to purchase about 70 percent of the power generated at the Daya Bay Nuclear Power Station, and 50 percent of that generated in the Guangzhou Pumped Storage Power Station, both in Guangdong province on mainland China. All locally generated power is thermally fired.

CLP Power's power purchase agreement with Daya Bay is set to end in 2013 and at that time the nuclear power plant and other IPPs from the Mainland might negotiate contracts with other suppliers, wholesalers or aggregators that are independent of CLP Power and HEC, introducing additional IPPs into the generation market. Importing electricity from mainland China has the added advantage of avoiding many of the environmental problems associated with power generation in Hong Kong.

INDONESIA

Indonesia is an archipelago with a fast growing population of 209 million. GDP per capita stands at US$ 2,739 (1995 US$ at PPP). The electricity system produced 100 TWh in 2001, 83 percent of it coming from thermal power plants, 11 percent from hydro plants, and 6 percent from geothermal and other sources.

Indonesia became a net oil importer in 2002, although with increased exploration it hopes to reverse that in the future. It still remains a large coal and gas exporter. Reducing its dependence on oil is a major energy policy goal. Indonesia held for some time a power supply surplus following a period of 15 percent demand growths annually and a sudden, subsequent recession after the Asian financial crisis in 1997. Now it is experiencing shortages of electricity and recently renegotiated the postponement of 27 IPP projects.

Research in atomic energy started in Indonesia as early as 1954 with the creation of the State Committee for Radioactivity Research. Other agencies created since have continued with nuclear research and various research reactors have been constructed also for that purpose. Today Indonesia has 3 nuclear research reactors in operation and is planning another 10,000 MW test reactor.

In 1972 a commission was established to study the installation of a nuclear plant and a feasibility study was concluded in 1996 just before the Asian financial crisis, when all plans for nuclear power were deferred indefinitely. More recently, in 2002 the National Long-Term Energy Planning 2000-2025 study included the possibility of a nuclear power plant in operation by 2016, and the latest National Energy Policy for 2004-2020 included nuclear energy as one possible alternative for the electricity generation fuel mix. Nuclear power is seen as a tool to achieve an optimum energy mix in terms of cost and impact on the environment, and to relieve increasing demand on fossil energy. Several areas have been identified as potential sites, with five of them preselected on the island of Java. With a government decision in the year 2005, a first reactor could be operational by the year 2016. [165] Another small power and desalination plant has been proposed for Madura using a Korean SMART

[165] BATAN (2004).

design reactor.[166] It must be pointed out, however, that more consensus among government agencies and the general public would be required for such decisions to be made.

MALAYSIA

Malaysia's total population is 24.3 million, enjoying a per capita GDP of US$ 7,802 (1995 US$ at PPP). Malaysia is well endowed with conventional energy resources such as oil, gas and coal as well as renewables such as hydropower and biomass. Reserves in 2001 amounted to 539 million cubic meters of oil, 2,310 billion cubic meters of gas and 1,483 million tonnes of coal. Oil and natural gas exports take up 29 percent of Malaysia's total indigenous energy production. At current production rates, oil and gas reserves are expected to last 18 and 35 years respectively. Most of the coal used in Malaysia is imported.

In 2001 electricity production totalled 84 TWh with 77 percent coming from thermal plants, mostly natural gas-fired. Hydropower was responsible for the remaining 23 percent. Malaysia has implemented a five-fuel energy strategy optimising the use of oil, natural gas, coal, hydropower, and renewable energy to achieve a balanced energy supply mix and reduce the nation's high dependence on oil and gas. For the power sector, this has meant substituting natural gas plants for coal-fired units and promoting the use of renewable energies wherever possible. According to government officials, nuclear power is currently not an option for Malaysia.

Malaysia has at present one research reactor in operation.

NEW ZEALAND

New Zealand is a small economy of 3.85 million people, with a per capita GDP income in 2001 of around US$18,340 (1995 US$ at PPP). The economy is reasonably well endowed with natural resources including abundant renewable energy resources, but small and likely declining oil and gas resources.

The New Zealand power system comprises around 8,600 MW. Total annual generation is around 39,000 GWh. Typically, around 60 percent of generation is from hydro, 7 percent from geothermal, 27 percent from natural gas and small amounts of generation from coal and other renewables. The amount of generation from coal and gas varies according to the amount of rainfall available to the hydro system as well as the availability (deliverability) of gas and coal.

The hydro system has an average operating rate of around 60 percent and is dominated by run-of-river, ie. use it or lose it, water. The hydro system is also somewhat seasonal and with storage limited to about 6 weeks demand. Hence, hydro and geothermal comprise baseload generation, with gas and coal providing mid- and peak- load. In the future, some peak load is likely to be oil-fired as it has been some 20 years ago. Generally, the limited ability to control the hydro system requires more mid-load (which effectively becomes baseload with low hydro availability), than might otherwise be the case.

Looking into the future, the cheaper and easier hydro options have already been developed, the availability of gas for electricity generation looks problematic and, although considered the backstop fuel, the use of coal faces political and environmental barriers, especially Kyoto Protocol targets as New Zealand has already ratified it. New Zealand has good and promising wind resources. Wind energy has been developed rapidly in the last few years, but it is unlikely to provide a significant share of new capacity in the long run.

Annual incremental requirements are estimated to be in the region of 100-150 MW per annum, depending on type and load. Currently, New Zealand electricity prices are among the lowest in the developed world. However the days of cheap power by world standards might be considered to be over since the lower cost opportunities have been exploited and with the economy facing a rising supply curve in terms of price.

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[166] WNA (2002).

New Zealand has had a nuclear-free policy since 1984 that includes the prohibition of nuclear powered ships entering its harbours. The use of nuclear power was briefly considered in the 1970s and is occasionally mentioned now, especially when low rainfall puts pressure on the system and results in high prices.

Recently the debate on nuclear power has been reinitiated with the decision on August 2004 by Environment Canterbury to include nuclear power in the discussion about future power sources. Nuclear power stations could be considered for operation in New Zealand by the year 2015 if resistance to implement coal-fired plants and their negative effects on the environment continues in the economy. Energy consultants have proposed building two nuclear stations north of Auckland to meet population growth and increasing electricity demand in the region. According to the same proposal, the comparatively lower future electricity demand in the South Island could be met with coal-fired units.[167]

Earlier in June of 2004, however, the Head of the Government-appointed Electricity Commission had stated that the size of a typical nuclear plant would probably not lend itself to an electricity system the size of New Zealand's. A reactor unit with a capacity of 1,200 MW connected to an electrical system with only 8,700 MW total capacity, would mean having to replace 1/7th of the system's power when that unit is down for maintenance or other reasons. He concluded that planning in small systems therefore should not include large-scale plants, and that smaller scale reactors under design at the moment had not been tested as yet. The Head of the Commission nevertheless recognised that oil, coal or natural gas plants would make it difficult for New Zealand to meet its commitments under the Kyoto Protocol, a problem not present if nuclear plants were used instead.[168]

PERU

The population in Peru is 26 million people and the economy has a per capita GDP of US$ 4,340 (1995 US$ at PPP). Peru is now a net importer of energy and imports 25 percent of its energy requirements mostly from Colombia, Ecuador and Venezuela. Of the total energy imported, 90 percent is crude oil used as refinery feedstock and 10 percent is coal. The Camisea gas field is still under development but is expected to produce 10 million cubic meters of gas annually and revenues of between US$ 5-6 million per year in royalties and taxes for 30 years when fully operational.

Peru's electricity system consists of 5,900 MW of installed capacity of which 50 percent is hydraulically powered and 50 percent is fossil fuelled. However in 2001 hydropower produced 85 percent of the 21 TWh of electricity produced.

Peru signed agreements to integrate its electricity grid system to those of Colombia and Ecuador. Peru expects to start exchanges to sell its excess hydropower to Ecuador sometime in 2004. This integration will possibly be expanded later on to Bolivia and Venezuela, the other two members of the Andean Community common electricity market to increase the overall efficiency.

There has not been talk on any official planning document of nuclear power for Peru. Peru has 2 research reactors in operation.

PHILIPPINES

The Philippines has a population of 78 million people and a per capita income of US$ 3,725 (1995 US$ at PPP). The Philippines indigenous energy reserves are relatively small with only about 24 million cubic meters of crude oil, 107 billion cubic meters of natural gas and 399 million tonnes of coal. It boasts however a large base of geothermal capacity that could make the Philippines an important producer of electric power from this renewable source. The Philippines relies on imports for 60 percent of its total energy supply. It currently has a policy of reducing imports of oil and coal to a minimum complemented with a policy to expand the use of natural gas for electricity production.

[167] Energy Central (2004b).

[168] New Zealand Herald (2004).

Main energy sources are: oil (49 percent), geothermal energy (35 percent), coal (13 percent), and gas (4 percent). Almost all coal requirements are imported. The Philippines production of oil, which recently was increased 20-fold, covers only 5 percent of the total domestic demand. The recent policy decision to prioritise the use of gas for power generation has increased the production of this fuel dramatically up to 1.51 mtoe annually and has opened more areas for prospective gas developers.

Electricity production totalled 55 TWh in 2001, of which 54 percent was generated in thermal plants fuelled mainly by coal and fuel oil, 33 percent came from geothermal plants and 13 percent was produced by hydropower plants. A high electricity demand growth rate of around 6 percent is expected in the Philippines for the next 20 years in average, and as much as 7,000 MW of additional generating capacity is being planned by the year 2010.

In the Philippines, atomic research began in 1958 with the creation of the Philippine Atomic Energy Commission, and with the nation becoming a member of the International Atomic Energy Agency. Construction of the 650 MW Bataan Nuclear Power Plant was initiated in 1977. It stopped for the first time in June 1979 after the Three Mile Island event and resumed in 1980 with the incorporation of additional safety features. By 1983 the plant was 90 percent complete when it received its first batch of nuclear fuel and applied for its operating permit; but the revolution of 1986 precluded it from starting operations when the new government took over the plant and decided to mothball it after an international team of experts declared the plant to be unsafe.

In May 1995 a Nuclear Power Steering Committee was created by executive order to reanalyse the nuclear power programme. At one point there were plans to convert the plant to coal or natural gas, but it was found that a nuclear upgrading would offer greater financial gain. The plant has actually remained stopped ever since its mothballing. The long term Philippine Energy Plan 1996-2025 included 2,400 MW of nuclear plants as part of the total 102,424 MW required for the year 2025. The more recent Philippine Energy Plan 2004-2013 has no mention of nuclear power for electricity generation, but the option is preserved in the long-term plan for consideration after 2020.[169]

The Philippines shut down its only research reactor in 1988.

SINGAPORE

Singapore is a small island nation with a population of 4 million. Per capita GDP in Singapore is US$ 20,841 (1995 US$ at PPP). Singapore's domestic energy supply depends on imported oil and gas. It imports annually around 42,465 ktoe of energy, mostly oil. Approximately half of its crude oil imports are re-exported as refinery products and the other half is retained for internal consumption. Oil accounts for 80 percent of domestic supply with natural gas accounting for the rest. Gas is mostly imported through pipeline from Indonesia.

The electricity supply comes from 9,000 MW of thermal power plants fuelled by heavy fuel oil and natural gas. The installed generating capacity is made up of 53 percent of conventional steam boiler-type plants, 30 percent of combined cycle plants, 11 percent of cogeneration plants, 5 percent of gas turbines and 1.5 percent of waste incineration plants.

THAILAND

Thailand has a population of about 61 million people and a per capita income of US$ 5,953 (1995 US$ at PPP). Thailand is highly dependent on energy imports particularly oil. In 2001 net energy imports accounted for 57 percent of energy supply in the whole economy. It imports 92 percent of the oil it consumes mainly from the Middle East although some oil is also imported from economies in the Association of South East Asian Nations (ASEAN) community, the Asia Pacific region and North America. Thailand has crude oil reserves of around 52 million cubic meters and a refinery capacity of 817,000 barrels per day, and has been exporting petroleum products recently due to a depressed local demand resulting from the retarded effects of the late 1990s Asian economic crisis. In terms of natural gas, Thailand only needs to import 21 percent of its requirements, which it does from

[169] PCIERD (2004).

Myanmar. Coal in Thailand is mostly used for power generation and industrial applications, and about one third of its needs are imported.

Almost all (94 percent) of Thailand's 102 TWh of electricity generation was produced by thermal plants. The residual 6 percent was supplied by hydro and other renewable sources. Thailand had an annual electricity demand growth rate of 5 percent in 2001 and expects growth rates to reach as high as 7 percent during the next 20 years.

Thailand has no policy for the time being for development and utilisation of nuclear energy. A nuclear plant project was initiated by the Electricity Generating Authority of Thailand (EGAT) in 1966 with a site for it approved in the early 1970s; but the project was cancelled in 1977 in view of the prevailing opposition globally and from the Thai public.[170] In 1997 a study on nuclear power was reinitiated, and at one point plans existed for the construction of one reactor in the succeeding 10 years with 5 more to follow afterwards.[171] The project was deemed unsuitable after the Asian economic crisis and plans have remained stagnated since. The high growth expected in demand might revive interest in the evaluation of nuclear plants for the future.

Thailand has one research reactor in operation and another one under construction.

VIETNAM

Vietnam is currently the economy in APEC most likely to become a new member of the community of economies with commercial nuclear power. Vietnam is home to 79.5 million people and has a per capita GDP of US$ 1,965 (1995 US$ at PPP). It is endowed with fossil energy resources such as oil, gas and coal as well as hydraulic resources suitable for power generation. In 2001, its reserves amounted to 420 million cubic meters of oil, 617 billion cubic meters of natural gas, 3,325 million tonnes of coal and more than 17,000 MW of hydro power capacity. Vietnam uses around 60 percent of its energy production and exports the remaining 40 percent, mostly crude oil and coal. According to the Ministry of Industry in Vietnam, the economy will become a net energy importer by 2015.

Electricity output in 2001 was 31 TWh and 60 percent of it was generated by hydro plants; the residual 40 percent was generated by thermal plants. Annual electricity demand growth is at a fast pace reaching a value of 15 percent in 2001, and it is projected to remain high at levels of around 8 to 15 percent for the next 20 years. The plan by Electricity Viet Nam (EVN) to meet this rapid growing demand is to construct 37 new power plants by the year 2010, including 22 hydropower plants, 8 oil and gas-fired plants and 7 coal-fired plants. EVN further projects it will need to construct as much as 100 new plants by the year 2020.

The government of Vietnam foresees major and increasing difficulties in meeting electricity demand after the year 2015 without resorting to either electricity imports, LNG or coal imports for power generation, or development of nuclear power.[172] The Ministry of Industry plans introducing nuclear power plants in the near future citing the urgent requirement to provide a stable supply of energy for socio-economic growth sparked by rapid development. Nuclear plants are seen as a way to diversify energy options to increase energy security while contributing to environment protection. Among the reasons to justify the need for a nuclear plant, the Ministry lists the following:[173]

- High economic growth rate of 7 percent annually expected in the near future
- Large population base of 80 million increasing to 98 million by 2020
- Coal reserves high but with low possibilities for exploitation, and limited reserves of oil and gas

170 EGAT (2004).
171 WNA (2002).
172 Vietnam Atomic Energy Commission (2004).
173 Vietnam Ministry of Industry (2004).

- Low possibility of developing renewable energies due to their unreliability and high cost in Vietnam
- Low possibility of developing energy saving technologies due to low technological and industrial capability, high capital needed, and low effectiveness
- Competitiveness of nuclear power
- Low emissions as compared to coal plants

Viability studies are underway since 1995 looking into all aspects of nuclear power: plant site selection, reactor technology options, radiation safety, waste disposal, and nuclear law. According to those studies, nuclear power can be competitive in Vietnam with a 5 percent discount rate and a capacity factor of 77.5 percent. Table 24 shows comparative costs for different generation technologies at a 5 percent discount rate. Two reactor models are considered, a light water reactor (LWR) with a capital cost of US$ 1,781 per kW of capacity and a LWR with a cost of US$1,676 per kW.

Table 24 Electricity generation costs for different plant types in Vietnam (US cents/kWh)

CCGT (Domestic gas)	CCGT (Import gas)	CCGT (Import LNG)	Conventional thermal plant (Import gas)	Conventional thermal plant (Domestic coal)	Conventional thermal plant (Import coal)	LWR reactor (US$1,781 /kW)	LWR reactor (US$1,676 /kW)
4.00	4.23	5.00	4.97	4.06	4.28	3.72	3.52

Notes: 5% discount rate. Capacity factor for nuclear plants is 77.5%.
Source: Vietnam Atomic Energy Commission (2004).

Important steps towards a possible decision to construct nuclear plants have been made: one is the identification of three suitable sites in Phuoc Dinh and Vinh Hai, both in Ninh Thuan province, and Hoa Tam in Phu Yen province; and another is the beginning in March 2003 of the elaboration of a nuclear law and related codes and standards with cooperation from Japan and the International Atomic Energy Agency. The studies are now focusing on the construction of 2 to 4 units of 1,000 MW each between 2017 and 2020, and a decision on whether to go ahead with the project should be made before 2008.[174]

Vietnam currently has a research reactor in operation.

174 Vietnam Atomic Energy Commission (2004).

CHAPTER 2

DRIVERS OF NUCLEAR POLICY IN APEC

INTRODUCTION

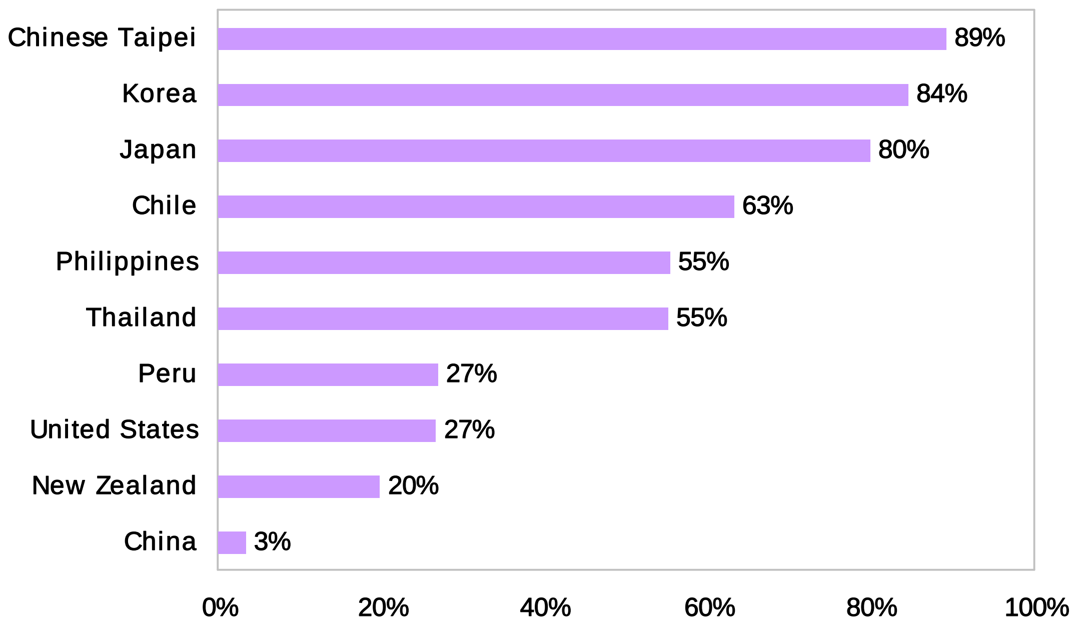
The policies of APEC economies with nuclear power generation plants described in the previous chapter are examined here to identify the most common drivers of nuclear energy policy in the APEC region. As discussed before, APEC is the region in the world that pushes for the most extensive plans for nuclear power development in the future. Other regions of the world by comparison, such as the European Union, have no plans for nuclear expansion except for a few isolated cases in France and Finland. The question then arises: what makes the Asia-Pacific region different?

By analysing the nuclear policies in APEC economies and understanding the reasons behind those policies, we can find the answers to that question and ascertain the future direction of nuclear energy in the region.

DRIVERS OF NUCLEAR POLICY IN APEC: ENERGY SECURITY

Most economies in the APEC region are either limited in energy resources, or have an imbalanced distribution of their energy resources that places strains on their economic growth. These economies have a high degree of dependence on foreign energy sources that will likely increase in the future to support secure and reliable supplies for their sustainable economic growth.

Figure 26 Import dependency of net energy importing economies in APEC, 2002 (Percentage)



Energy security is one of the main reasons for active nuclear power programmes in APEC. Those economies with the highest import dependency are the ones with the highest nuclear share in power generation among the 8 APEC economies with nuclear power programmes. Figure 26 shows all the energy importing economies in APEC and their degree of import dependence. Five of the 8 economies with nuclear programmes are on the list. Table 25 lists all eight APEC economies that have nuclear plants and compares their import dependency to nuclear share in power generation. To offset import dependency, the top four economies have maintained high shares of nuclear power in generation that go from 20 percent as in the case of United States, to as much as 40 percent, as in the case of Korea.

China, not a heavy importer at present, and Russia, an energy exporter, experience a different kind of energy security concern: that of having an uneven distribution of energy resources. China is developing nuclear power in coastal and eastern provinces that are poorly endowed with energy resources and where most of its industrial activity lies. Russia's nuclear reactors are concentrated in the European part of its territory; and even though a fraction of its oil and gas resources are available in the area, Russia has plans to increase nuclear capacity in the region to channel those resources for export into Europe and elsewhere.

Table 25 Nuclear share in power generation and import dependency in APEC nuclear economies (Percentage)

Economy	Import dependency (%)	Nuclear share in power generation (%)
Chinese Taipei	89.2	21.5
Korea	84.4	40
Japan	80.0	25
United States	26.8	20
China	3.4	2.2
Mexico	-48.5	5.2
Canada	-53.3	12.5
Russia	-65.5	16.5

Sources: Import dependency figures for 2002 from IEEJ APEC Energy Database.
Nuclear share in power generation figures for 2003 from IAEA PRIS database.

In either case, whether because of resource deficiency or resource distribution imbalance, most of these economies foresee becoming more import dependent on oil and natural gas, and share the concern that a large percentage of the imports will come from Middle East economies that are seen as politically unstable and that have in the past used energy resources to obtain political and financial gain from their customers.

Uranium on the contrary is amply available from OECD economies and the international market has a history of stable supply with low volatility in prices. Almost half of the uranium reserves are owned by OECD economies. Forty-four percent of the world's reserves are inside APEC itself. Australia and Canada alone own one third of the world's known reserves and today also account for one half of the world's annual production (see Chapter 4: Resources and Depletion of Nuclear Fuel Materials).

Uranium is therefore more readily available to most APEC economies, and thus those economies with less indigenous resources tend to rely more on nuclear power generation.

DRIVERS OF NUCLEAR POLICY IN APEC: HIGH ELECTRICITY DEMAND GROWTH

Expectations for a high electricity demand growth can also put strain on energy resources and is another reason for diversification of power generation sources. APEC economies with the most aggressive plans for nuclear expansion are among the economies with the highest expected electricity demand growths.

Energy diversification schemes place emphasis on sources that provide the highest reliability and security of supply. Nuclear power is seen as such by a number of economies in APEC and in other Asian economies outside of APEC.

The APEC region is characterised by fast growing electricity demand. According to APERC's *Outlook 2002*, final consumption of electricity increased for the last 20 years faster than any other form of energy in APEC, and the trend will continue for the next 20 years at an annual average growth rate of 3.2 percent for all APEC economies.

Table 26 APEC economies, plus India, with the highest expected electricity growth rates, 2000-2020

Economy	2000-2020 Population average annual growth rate (%)	GDP/capita in 2001 (1995 US$)	2000-2020 GDP average annual growth rate (%)	2000-2020 Electricity average annual growth rate (%)	Official nuclear expansion plans
Vietnam	1.34	390	6.22	8.2	2-4 GW by 2019[a]
Indonesia	1.15	1,036	4.80	6.6	
Chile	1.20	5,385	5.47	6.2	
Malaysia	1.46	4,715	4.94	6.1	
Philippines	1.49	1,182	4.90	6.0	
Mexico	1.53	3,737	3.80	5.7	
China	0.72	880	7.14	5.6	32-40 GW (total) by 2020
India	1.38	492	5.82	N.A.	20 GW (total) by 2020
Thailand	0.94	2,869	4.91	5.5	
Korea	0.59	13,512	4.49	4.7	28 units (total) by 2015
Singapore	1.64	26,868	4.70	4.7	
Hong Kong	0.72	25,122	4.10	4.7	
Peru	1.55	2,304	4.68	4.0	
Chinese Taipei	0.77	14,887	3.36	4.0	
Russia	-0.26	2,462	5.08	3.8	50 GW (total) by 2020

Notes: a) Under evaluation at present.

Sources: Population aagr, GDP aagr, and electricity aagr from APERC (2002) and related database.
GDP/cap. from EDMC (2004).
Nuclear plans from each economy's official policies.

Table 26 lists APEC economies plus India with the highest projected electricity and economic growth rates for the next 20 years, according to APERC's *Outlook 2002*.

Listed in the table also are the plans for expansion of the nuclear economies among this group. China, India, Korea, and Russia are assigning nuclear power an increased role in the future of their electricity systems in view of their fast-paced expectations for GDP and electricity demand growth. The burden of high electricity demand growth in these economies is compounded by having limited or unevenly distributed resources as was seen in the previous section.

Among the economies listed in Table 26 with high projected economic growths and no present nuclear programmes, a few have considered nuclear power as an alternative option for their electricity systems. Vietnam, Indonesia, Philippines and Thailand have considered plans for nuclear plants at one point or another. For Vietnam, with the highest electricity demand growth rate expected among APEC economies, there is a high possibility of a favourable decision on the construction of 2 to 4 nuclear reactors to be completed by 2020.

The IAEA cites high energy demand and the need for economic development as the main reasons why some parts of Asia continue construction of nuclear reactors while Western Europe and the United States have not.[175] The IAEA indicates that China and India, with two-fifths of the world's population, are among those countries that face enormous energy demands driven by the need to combat poverty and hunger.

If we follow this argument it is interesting to note from the data in Table 26 that Vietnam, China and India, economies with plans for nuclear construction, are the three economies with the lowest GDP/capita and thus with the most pressing need for economic growth. Further, it can be seen from the list that 4 economies with nuclear expansion plans occupy 4 of the top 5 spots when the list is organised in order of highest projected GDP growth rate.

DRIVERS OF NUCLEAR POLICY IN APEC: SUSTAINABLE DEVELOPMENT

Sustainable development is cited by every APEC economy with active nuclear programmes as a major reason for having and promoting the policy. For these economies, nuclear power is an important component in their overall strategy to curb greenhouse gas emissions. Six economies in APEC are included in Annex B of the Kyoto Protocol that defines targets for specific parties to reduce their present levels of emissions as shown in Table 27. With Russia's ratification of the instrument in late 2004, the Kyoto Protocol will soon come into effect and become legally binding to the parties within the first few months of 2005.

Table 27 APEC economies included in Annex B of the Kyoto Protocol with estimated contribution to future emissions

Economy	Target emissions by 2008-2012, percentage relative to 1990 levels (%)	Projected increase in CO_2 emissions, 1999-2020 (million tonnes/yr)	Share in projected increase in CO_2 emissions, 1999-2020 (%)	Nuclear share in power generation (%)
United States	- 7	2,104	25.3	20.3
Canada	- 6	175	2.1	12.3
Japan	- 6	173	2.1	34.5
Russia	0 (same level)	1,037	12.5	16
New Zealand	0 (same level)	7	0.1	No nuclear
Australia	8	166	2	No nuclear

Sources: Target emissions from Kyoto Protocol.
Projected increase in emissions from APERC (2002).
Nuclear share in power generation from IAEA (2004a).

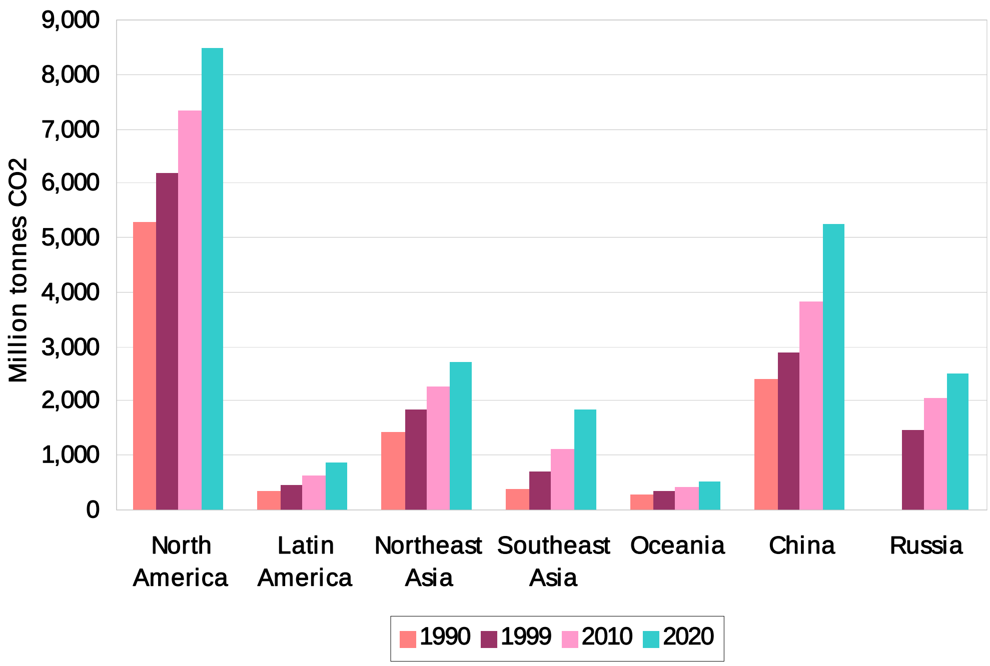
According to APERC's *Outlook 2002*,[176] CO_2 emissions in the whole of the APEC economies will increase by 8,315 million tonnes in the period from 1999 to 2020. As shown in Figure 27, four regions will account for the largest increases in emissions in the next 20-year period in APEC: North America (Canada and the United States), China, Northeast Asia (Chinese Taipei, Hong Kong, Japan

[175] IAEA (2004d).
[176] APERC (2002).

and Korea), and Russia. Four of these are listed in Annex B of the Kyoto Protocol. Three of them have ratified or are in the process of ratifying the Protocol: Canada, Japan and Russia. United States has stated its intentions not to ratify the Protocol, but is engaged in its own policies and measures to fight global warming. These four economies therefore have firm emission reduction targets to meet, and interestingly, all have nuclear power programmes. These economies will be relying heavily on their existing nuclear fleets as part of their strategies to curb energy-related greenhouse gas emissions until their decommissioning in the rather distant future.

One of the conclusions of the APERC Outlook 2002 was that unless additional measures are adopted in the next 10-year period, APEC economies are unlikely to meet the target emissions required by the Kyoto Protocol. Thus, early retirement of the existing nuclear power plants could make it harder for these economies to meet the Kyoto targets.

Figure 27 Historical and projected annual CO_2 emissions from energy consumption in APEC by region, 1990-2020 (Million tonnes of CO_2)



Source: APERC (2002).

DRIVERS OF NUCLEAR POLICY IN APEC: LOW NUCLEAR PLANT GENERATION COSTS

Currently operating nuclear plants are competitive in generation costs with other forms of electricity generation in many parts of the world. Interest rates and the high investment capital required for nuclear plants inhibits new constructions nowadays, but for most currently operating plants their high levels of depreciation, low fuel costs and improved generation efficiency has lowered their generation costs and is an incentive to keep the plants operating.

In APEC economies with good performance parameters in their nuclear fleets, low operating costs are an influential driver to maintain their nuclear programmes active, if not by planning new plant constructions, at least by keeping their existing reactors in operation for as long as possible. This last fact is confirmed by the trend to renew the operating licenses of nuclear power plants to extend their commercial lives such as is happening in Canada, Japan, Russia and the United States.

In Canada a number of reactors that were laid up in Ontario due to reports of decaying performance and safety conditions were refurbished and brought back online with extended lifetimes. Rather than shutting down the plants permanently, it was decided that maintaining the plants in operation made more economic sense than the construction of new gas-fired units. Quebec Hydro and New Brunswick Power are also planning the refurbishment of one reactor each to extend their lifetimes by 25-30 years.

In the United States improving performance parameters and low fuel costs have made nuclear plants achieve lower power production costs than all other competing facilities, except hydro. As noted in the section on the United States previously, without construction of new nuclear plants, the electricity generated by nuclear power nevertheless has increased since 1990 by 35 percent, equal to 200 TWh and equivalent to 25 new 1,000 MW reactors. In 2002 nuclear energy for the 4th year in a row was the cost leader for baseload generation. Production costs including only cost of fuel plus operation and maintenance, averaged 1.71 US cents/kilowatt-hour (c/kWh, in 2003 US$) for U.S. nuclear plants compared 1.85 c/kWh for coal plants, 4.06 c/kWh for natural gas and 4.41 c/kWh for oil-fired plants.

This has proven an important incentive for nuclear operators to maintain their plants running and in some cases to modify the plants to increase their power output (power uprates). In 2003 sixteen life extension licenses had been granted and it is now expected that 80 percent of all plants in the nation will apply for similar extensions. Power uprates have contributed 4,000 MW of additional capacity, and an estimated 1,000 MW more are expected in the next five years.

Table 28 Average electricity production costs for different plant types in the United States, 2002 (2003 US cents/kWh)

	Nuclear	Coal	Natural gas	Oil
Average electricity production costs, US cents/kWh	1.71	1.85	4.06	4.41

Source: NEI (2003a).

Japan has a long experience with nuclear power, and has successfully applied that experience into improving operation margins to push nuclear generated electricity prices down. These prices are high by world standards (see Chapter 3: *Economic Competitiveness of Nuclear Power*), but the prices of competing fuels for power generation in Japan also tend to be higher than world norm. According to the Ministry of Economy, Trade and Industry (METI), generation costs of nuclear plants are the least expensive among the existing options. In Table 29 the overall costs of electricity generation with nuclear reactors in Japan is 5.5 c/kWh, lower than those for oil, coal and natural gas even if that cost includes the cost of fuel reprocessing and plant decommissioning. As more and more nuclear plants in Japan reach their 16-year legal depreciation periods, it is expected that generation costs will continue to improve.

Table 29 Electricity generation costs for different plant types in Japan, 1999 (US cents/kWh)

	Nuclear	Hydro	Oil	LNG	Coal
Overall generation costs, US cts./kWh	5.5	12.7	9.5	6.0	6.1

Notes: Exchange rate: 107 Yen/US$.
40 years plant lifetime and 80% capacity factor.
Calculated at 1998 average fuel prices in Japan.
Source: METI.

Chapter 3: *Economic Competitiveness of Nuclear Power* looks deeper into the facts that influence the overall costs of nuclear power generation costs.

CONCLUSION

The main drivers of nuclear energy in APEC are:

- Energy security in a context of scarcity or unevenness in the distribution of energy resources
- High electricity demand growth and the need for energy source diversification
- Sustainable development and the pressing need to reduce greenhouse gas emissions from power generation
- Low nuclear plant generation costs as an incentive to maintain existing nuclear fleets running

APEC economies with nuclear programmes, especially those in Asia, see themselves either as poor in energy resources (Japan, Korea, Chinese Taipei) or as having an uneven distribution of energy resources (China, Russia, and non-APEC India). These economies are concerned about becoming more dependent on imported oil and gas in the future, or about depending too much on resources needed for export, in the case of Russia. For these economies uranium is more readily available and therefore see advantage on relying more on nuclear generation.

A high expected electricity demand growth brings with it the need to diversify power generation sources. The problem is compounded in some APEC economies by the scarcity of viable alternatives. The need for economic development in economies with low income levels makes using secure and reliable power generation alternatives a necessity. The enormous energy demands expected in the future together with a deficiency in indigenous energy resources, has driven the construction of a large fraction of new nuclear plants in developing economies in Asia in recent years. Other developing economies in APEC for the same reasons will take on new nuclear programmes and construct plants in the near future.

Sustainable development forces the need for clean power generation technologies. Nuclear energy has almost no credible competitors for large-scale baseload generation with low contaminating emissions. APEC economies will be using their nuclear fleets as an important part of their sustainable development strategies.

Low nuclear plant generation costs have made these plants attractive in today's power markets and that has become in APEC and elsewhere a strong incentive to maintain the inventory of currently operating nuclear reactors active.

SECTION 2

ISSUES

CHAPTER 3

ECONOMIC COMPETITIVENESS OF NUCLEAR POWER

INTRODUCTION

Out of the different barriers currently facing the expansion of nuclear energy, probably the most important is cost competitiveness. After all other issues are dealt with: nuclear safety, waste disposal, public opinion and proliferation, in the end nuclear power will only be viable if it can be competitive in today's electricity markets.

It has been the subject of much discussion that internalising the cost of externalities into competing forms of electricity generation can make nuclear power projects, which to a large extent already include them, more attractive to undertake. The establishment of carbon trade practices or implementation of carbon taxes could put nuclear power and renewable energy technologies in a better level of competitiveness. Efforts to promote the inclusion of nuclear projects under the Clean Development Mechanisms are expected to continue. However, all these measures are policy dependent and it is not possible to predict when and to what extent they can be adopted. For nuclear power to be a valid alternative fuel source for the future, it has to be economically competitive on its own.

It is worth revisiting the standing of nuclear power generation costs today. There are factors that point to the possibility of greater competitiveness for nuclear power plants. A number of vendors have announced lower capital cost estimates for their new models of advanced-type reactors. The relative stability of reactor fuel prices put nuclear energy at an advantage compared to the volatility of alternative fuel prices. Also, running costs for nuclear units in many places have continued to improve in recent years. The total result is that the prospects for the economically competitive construction and operation of new nuclear units appear to be better today than was the case just 5 to 10 years ago.

In this chapter we discuss the different aspects that influence the overall economic competitiveness of nuclear power.

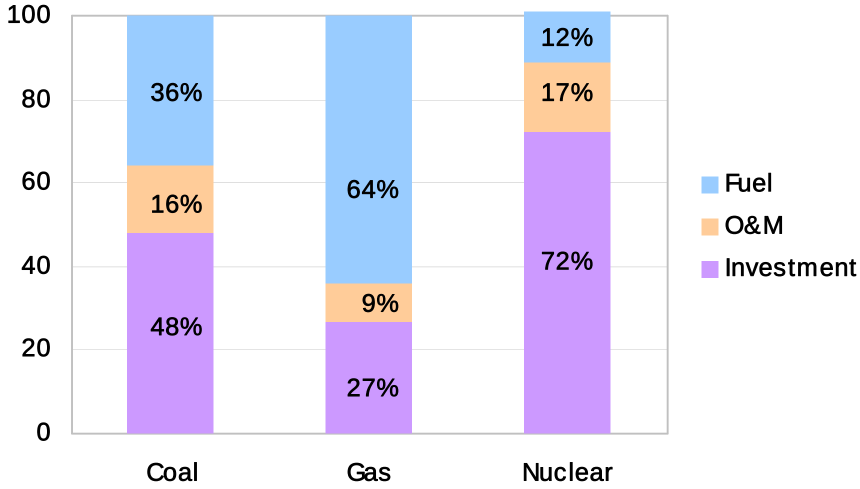
FUEL COSTS

Figure 28 shows the structure of electricity generation costs for nuclear power compared to coal- and natural gas-fired plants at a 10 percent discount rate according to calculations by the OECD's Nuclear Energy Agency (NEA). For nuclear power plants, fuel and operation and maintenance costs represent a smaller percentage of the overall costs than for the other type of plants, and capital costs become the overriding factor in the overall economic performance.

With fuel costs representing a smaller share of the total costs of nuclear power generation, variations in such costs do not impact the cost of generation as much as is the case for fossil fuel generation technologies. Further, past trends show that the cost of nuclear fuel and nuclear fuel services has been less volatile than for other fuels, and on a downward trend in recent years.

The allure of nuclear energy has traditionally been its low fuel costs as compared to fossil fuel-fired plants. The cost of nuclear fuel has different components: the costs of raw uranium, processing, enrichment, and fuel fabrication. It also has to account for the costs of processing the spent fuel and managing the radioactive wastes. Still, accounting for the costs of all these different components, the cost of nuclear fuel is typically less than 15 percent of the total cost of electricity (up to around 25 percent at 5 percent discount rate).[177] This represents only one third the portion of fuel in a comparative coal plant and around one fifth that of a natural gas plant as shown in Figure 28.

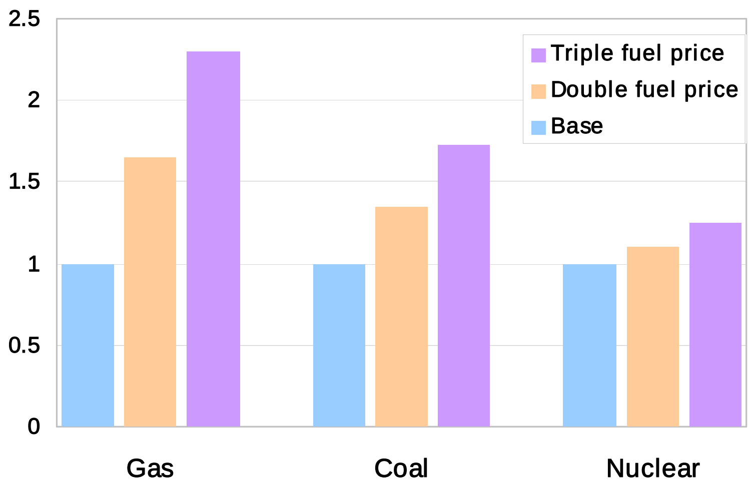
Figure 28 Structure of electricity generation costs at 10% discount rate in the OECD (Percentage)



Source: NEA (1998).

It then follows that nuclear generation has a relatively lower sensitivity to fuel price fluctuations than coal or gas plants. In its latest study on the costs of electricity generation in 1998, the OECD's NEA estimated that a doubling in the price of nuclear fuel would result in only a 10 percent increase in the generation cost including capital, as shown in Figure 29. The conditions assumed for that study have changed since the time it was finished, but the numbers are still representative of the general tendencies. The increase in nuclear generation costs due to an increase in fuel price amounts in the study to only about one third of the increase in coal generation, and one fifth the increase in gas-fired costs.[178]

Figure 29 Sensitivity of generation cost to fuel price increases (Base = 1)



Source: IEA (2001a)

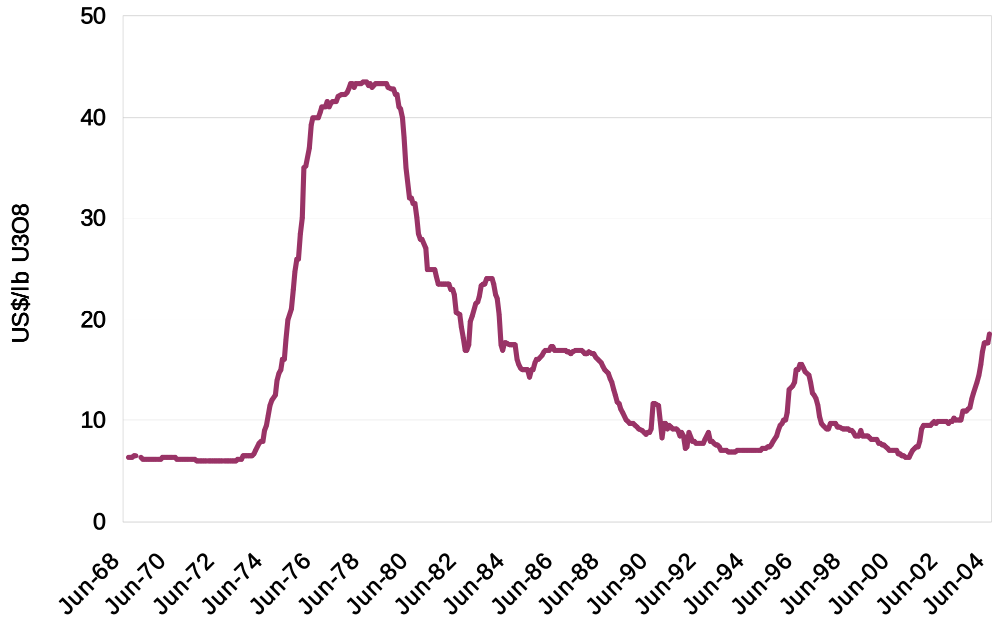
[177] NEA (1998).
[178] IEA (2001a) with data from NEA (1998).

If the price of only the raw uranium component doubled, the increase in generation cost for a nuclear plant would be of only 2 to 4 percent. This is due to raw uranium material accounting for only about one third of the cost of nuclear fuel in light water reactors, and about one half of the cost of fuel in heavy water reactors (which do not require conversion and enrichment). Fuel cost is therefore more dependent on the costs of the other components of the fuel: uranium conversion, enrichment, fuel fabrication and radioactive waste disposal. These services are generally handled by separate entities, and therefore follow independent price tendencies.

The price of uranium declined steadily since reaching peak values in 1979 and stabilised at a price of around US$ 10 per lb of U_3O_8 (uranium oxide) between 1995 and 2002. It appears to have started only recently an increasing tendency since 2003, according to prices published by Trade Tech Uranium Information[179].

Prices that peaked in 1979 as a result of an accelerated rate of reactor construction in part due to the OPEC oil embargo, later started a sustained decline from excess inventory produced also (paradoxically) by the fall in electricity demand resulting from the OPEC actions of the 1970s and subsequent cancellation of reactor construction orders, the falling out of favour of nuclear plants worldwide, and the entry of supplies from the Soviet Union into the western uranium markets. International market restrictions placed on ex-Soviet uranium helped stabilise the prices after 1994 but a recent relaxation of such restrictions and the general notion that surplus quantities of uranium supplies still exist in commercial stockpiles made the price of uranium continue its declining trend. Starting in 2003 and continuing in 2004, prices have started to rise again although based on temporary conditions, according to Trade Tech Uranium Information. A fire at a uranium processing plant in Australia, a flood at a uranium mine in Canada, and an offsite discharge of uranium-bearing gas from a processing plant in the United States have had lingering effects on prices up until June 2004, but whether the upgoing trend will continue is difficult to predict as of now. Figure 30 shows the trend in uranium price since 1968 based on spot prices of U_3O_8 (uranium oxide) in nominal U.S. dollars as reported by Trade Tech Uranium Information.[180]

Figure 30 Monthly exchange (spot) price of U_3O_8 (Nominal US$/lb U_3O_8)



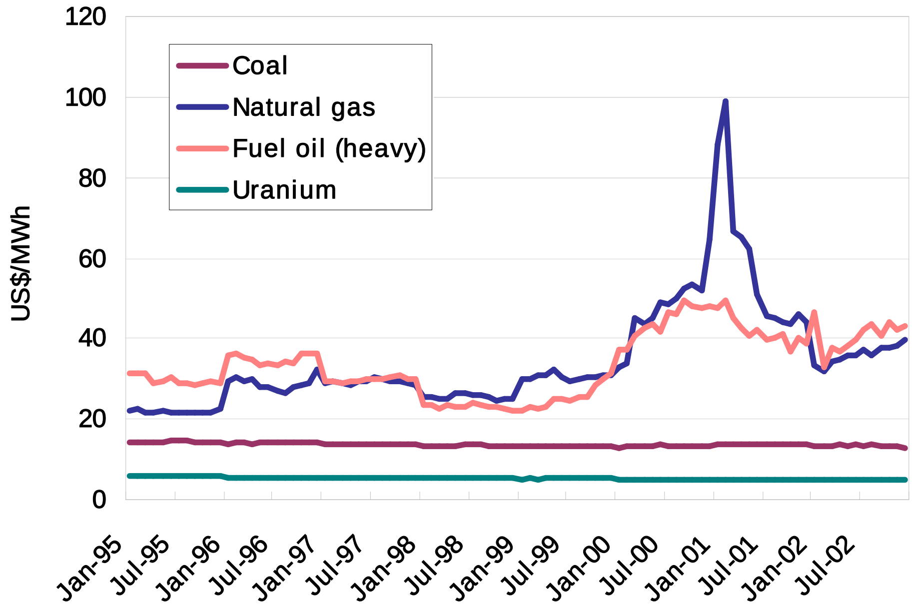
Source: Trade Tech (2004).

179 Trade Tech (2004).

180 Trade Tech (2004).

Figure 31 shows monthly fuel costs in US$/MWh in the United States as calculated by the Nuclear Energy Institute (NEI), and gives an indication of the relative stability of uranium prices (per MWh) as compared to the volatility in the prices of fossil energy sources (per MWh).

Figure 31 Relative price volatility of energy sources in the United States (Monthly fuel cost in US$/MWh)



Source: NEI (2003b).

Trends in the prices of conversion and enrichment services can be seen in Figure 32 and in Figure 33. Uranium conversion long-term contracts prices as reported by COGEMA have been stable for the last 15 years and have since 1995 started to decrease due to the added availability of uranium material from dismantled nuclear weapons. The closure of the Sequoyah large conversion plant in the United States in 1992 eliminated some of the existing overcapacity and has made spot prices, standing at one point at around half the price of contract prices, converge with these.[181]

For enrichment services, contract prices have been trending downward for 20 years due to overcapacity in the market, as can be seen from COGEMA data in Figure 33. Spot prices on the other hand started moving upward and have converged with long-term prices due to market uncertainty following the creation in 1992 of the United States Enrichment Corporation (USEC), which absorbed the USDOE's enrichment enterprises that handled a third of the world market. The USEC was given the directive of running the enrichment enterprise on a commercial basis and finally sell the business to the private sector, a process that was completed in July 1998.[182] Aggressive competition in an over-supplied enrichment market and the continued existence of surplus military enriched uranium are likely to maintain a downward trend in the mid-term future.

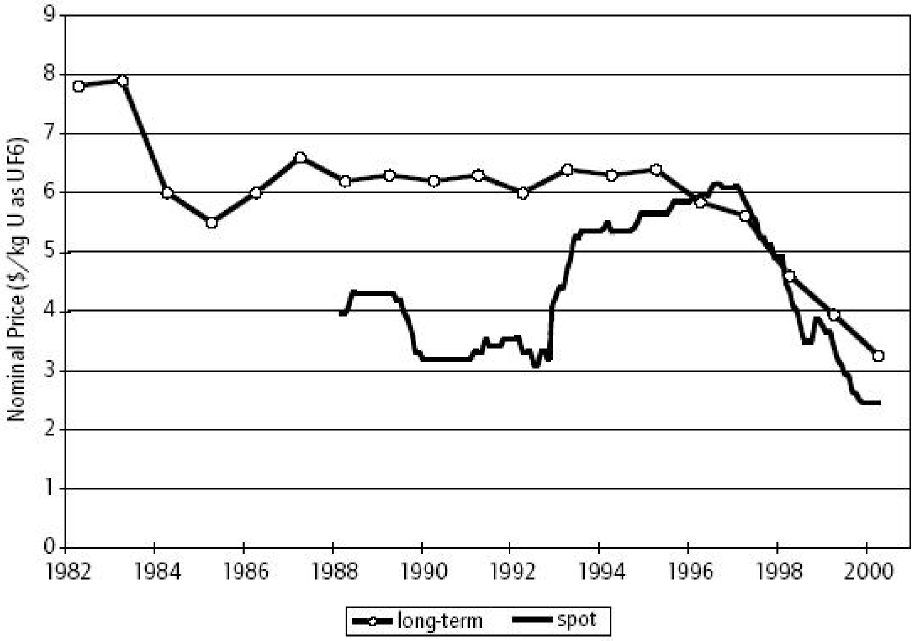
Overcapacity exists as well in the fuel fabrication segment (the last step of nuclear fuel production). For many years this segment was very specialised by reactor type and region, creating large regional price differentials: fuel fabrication prices vary by a factor of three between Japanese, European and North American markets.[183] More competition is anticipated as suppliers are becoming more capable of producing fuel for different reactor designs.

[181] NEA (1998).

[182] Nuclear Engineering International (2003).

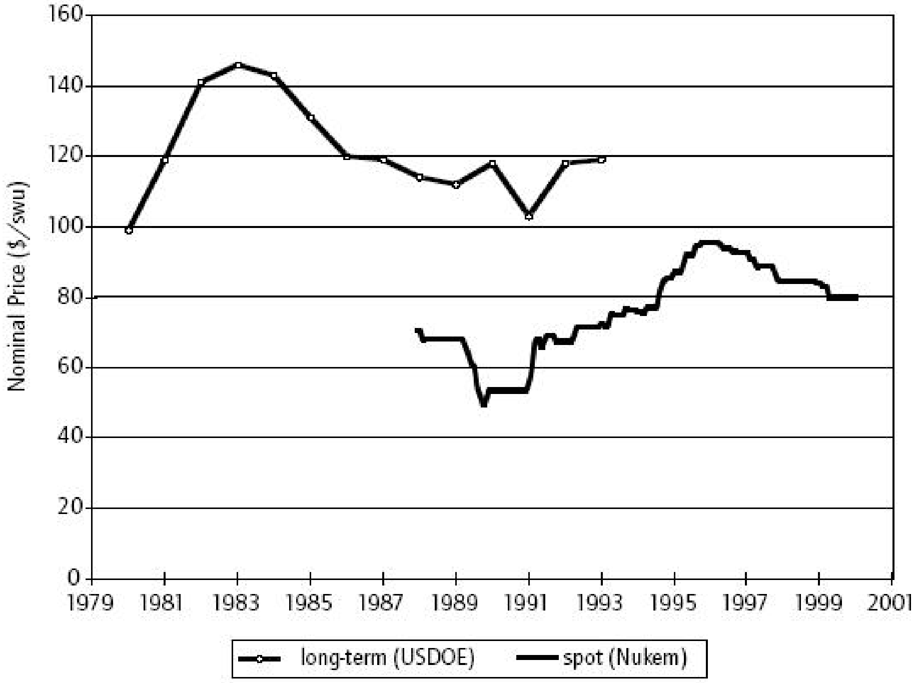
[183] IEA (2001a).

Figure 32 Long-term and spot price of uranium conversion services, 1982-2000 (Nominal US$/kg U)



Sources: Trade Tech for spot prices, COGEMA for long term conversion prices before 1996; by way of IEA (2001).

Figure 33 Long-term and spot price of uranium enrichment services, 1980-2000 (Nominal US$/swu)



Note: swu, or separative work unit, is a unit used for uranium enrichment services.
Sources: Nukem for spot prices, USDOE for long-term prices; by way of IEA (2001).

An indication of how total nuclear fuel cost stands relative to fossil alternatives can be seen in Table 30. It shows the total cost of nuclear fuel in the United States which in 2002 averaged at 0.45 US cents/kWh, compared to 1.36 US cents/kWh for coal and 3.44 US cents/kWh for natural gas.[184]

As will be shown in the chapter on nuclear fuel resources, availability of fuel materials is not a concern for the future of nuclear power, and therefore the expectation is for prices to increase predictably as less expensive resources are depleted and more expensive to produce resources come into play.

Table 30 Average fuel costs for electricity generation in the United States, 2002 (US cents/kWh)

	Nuclear	Coal	Natural gas
Fuel cost US cents/per kWh	0.45	1.36	3.44

Source: NEI (2003a).

However, some experts warn of possible instability in the future. The uranium market has historically lacked a supply-demand balance. As explained before, prices of uranium have been driven down by oversupply and even today the magnitude of existing surplus including both civil and military stockpiles is not fully known and hard to assess. Forecasting the price of a commodity is difficult in the absence of a long-term equilibrium. There has also been chronic overcapacity in enrichment services, and these have not been fully competitive. Enrichment facilities have been operated up to now mostly by government entities, with the United States Enrichment Corporation having been just recently privatised in 1998 as noted. Further, three large plants account for 85 percent of the OECD enrichment capacity,[185] meaning that the loss of one plant could have a major impact on supply.

PRODUCTION COSTS

Production costs for nuclear power plants have been decreasing for the last two decades mainly due to the improvement of reactor performance parameters that in turn have resulted in higher energy outputs.

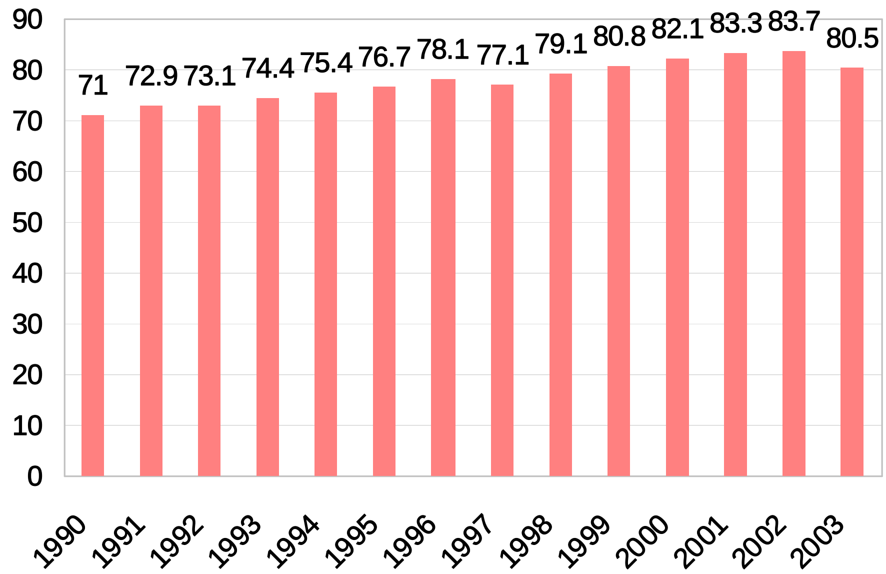
Improved operations and reliability in nuclear power plants have increased energy output and improved production costs in many nations over the past 20 years. By 'production costs' we refer here to fuel costs plus operation and maintenance. According to the IAEA (Figure 34) the average capacity factor for nuclear reactors operating worldwide has increased from 71 percent in 1990 to 80.5 percent in 2003. The capacity factor is the percentage of power generated over a year as compared to the possible total, and is a measure of the reliability of the plant's operation.

Data from the Nuclear Energy Institute show how the cost of electricity production in the United States has also improved to the point of achieving the lowest power production costs compared to all other competing facilities except hydro. In other words, compared to any source of expandable baseload electricity. With low fuel costs and higher performance parameters, nuclear energy in the United States was the cost leader for baseload generation for four consecutive years between 1999-2002. Figure 35 shows average production costs in the United States encompassing only fuel plus operation and maintenance, using data from the U.S. Utility Data Institute and Resource Data International. The data in the last three years evidences the effect of fuel price volatility on the cost of electricity production using oil and natural gas.

[184] NEI (2003a).

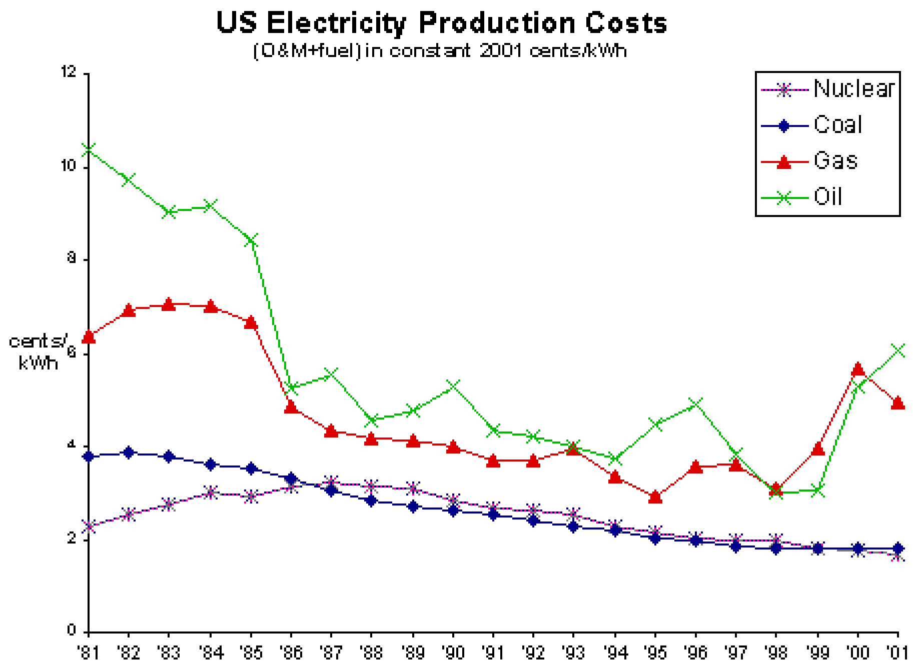
[185] IEA (2001a).

Figure 34 Average energy capacity factor worldwide, 1990-2003 (Percentage)



Source: IAEA PRIS.

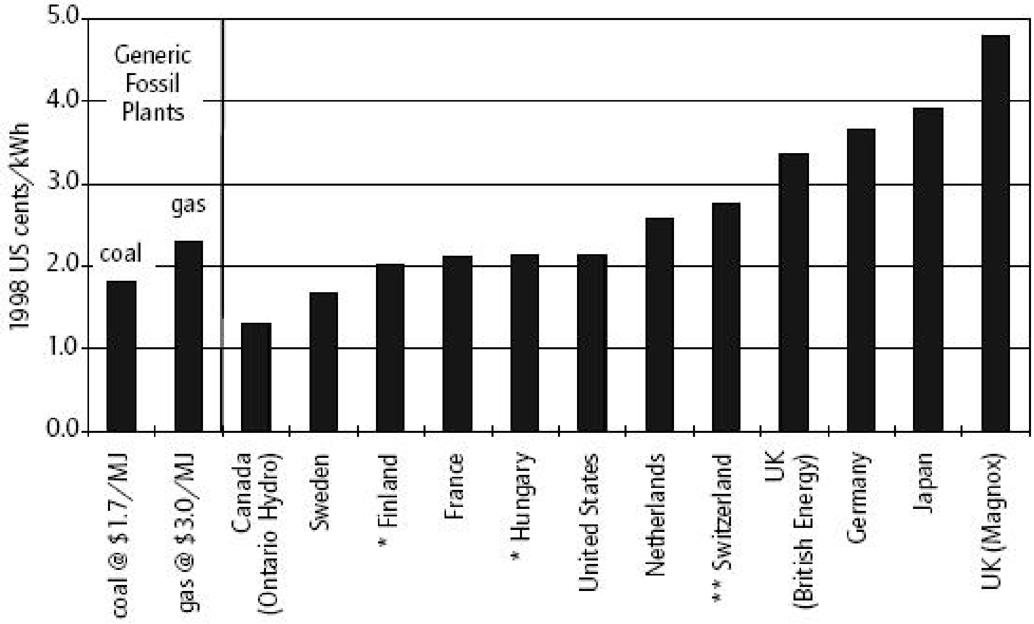
Figure 35 Comparative electricity production costs in the United States, 1981-2000 (2001 US cents/kWh)



Source: U.S. Utility Data Institute (pre 1995) and Resource Data International (1995-on), by way of World Nuclear Association.

Figure 36 shows average fuel and operation and maintenance costs of nuclear power plants in different OECD economies in 1998 US cents/kWh. According to the data from the IEA, the operating costs in many OECD member countries are in line with generic coal- and gas-fired plant operating costs. Economies with higher nuclear operating costs usually also have higher costs for competing non-nuclear plants. Such is the case of Japan, for instance (see the section on Japan in Chapter 1: *Nuclear Power Policies in the APEC Region*).

Figure 36 Average operating costs of nuclear plants in OECD economies (1998 US cents/kWh)



Source: IEA (2001).

CAPITAL COSTS

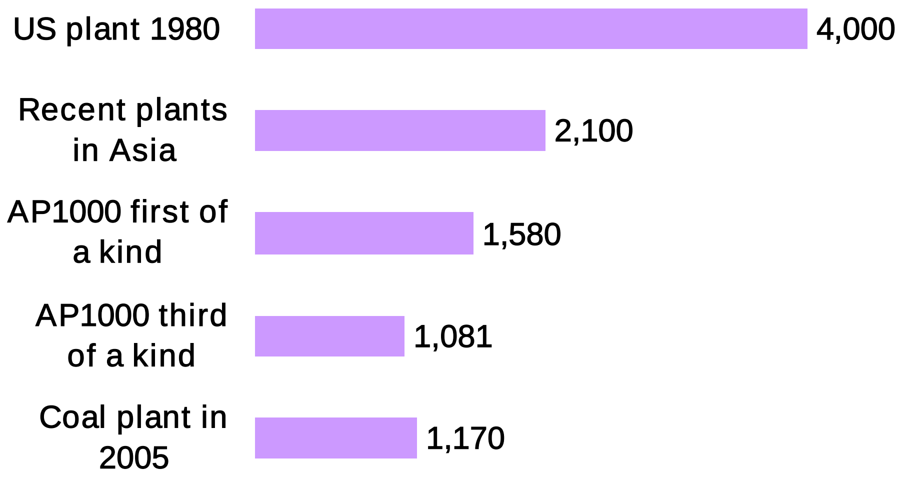
Capital costs dominate the economics of nuclear power, as the 72 percent share shows in Figure 28 calculated at a 10 percent discount rate. Even at a discount rate of 5 percent, investment costs in average for nuclear power are still around 55 percent. Therefore the competitiveness of nuclear power will be strongly dependent on how much can be achieved in the reduction of investment costs.

Reactor vendors have announced new generation designs that promise to have competitive construction costs that are getting closer to the value of US$1,000 per kW. This is generally regarded as the point at which nuclear plants can be totally competitive with other alternatives for baseload capacity. General Electric's 1,350 MW ABWR (advanced boiling water reactor) with incremental safety and operational improvements over current generation reactors has a cost estimate of between US$ 1,400 to US$ 1,600/kW (in 2000 US$), assuming that 50 percent of the first-of-a-kind-engineering (FOAKE) costs are financed by the government. Westinghouse (now a part of the British Nuclear Fuels Limited Group) estimates that the cost of its first two-unit 1,100 MW AP1000 advanced pressurised water reactors can have construction costs of between US$ 1,210 to US$ 1,365/kW (2000 US$). The assumption for this figure is that all of the first-of-a-kind-engineering costs[186] would be covered by someone other than the plant purchaser. Westinghouse also assumes that construction experience will help in further reducing the cost down to US$ 1,040/kW (2000 US$) for a third of a kind two-unit plant. Atomic Energy of Canada Limited (AECL) for its part estimates

[186] Extra expenses incurred in new models due to engineering design and the construction learning process. See *Impact of first-of-a-kind engineering* section ahead.

that a third of a kind, twin unit ACR-700 advanced CANDU plant could have a cost of about US$ 1,100 to US$ 1,200/kW (2000 US$).[187]

Figure 37 Comparative overnight capital costs for nuclear plants in the United States (2002 US$/kW)



Source: EIA (2004b).

Figure 37 compares real investment costs for nuclear plants already constructed to the projected costs of new plants. According to the EIA,[188] nuclear plants that started construction in the 1970s (finished in the 1980s) averaged construction costs of around US$ 4,000/kW (2002 US$) due to unforeseen additional regulatory requirements during construction, licensing problems, misestimation of capacity requirements and a misestimation of the savings of constructing larger-scale plants, among others. But nuclear plants that have been constructed in China and Korea in the last few years have been able to average lower costs of around US$ 2,100/kW. Even in Japan, where costs tend to be more expensive due to the higher costs of land, salaries and others, the construction of TEPCO's Kashiwazaki Kariwa-6 and -7 ABWRs required a similar capital cost of US$ 2,250/kW.[189]

The cost assumed by the EIA for a pulverised coal plant in 2005 is US$1,170/kW. Compared to those values shown, the costs predicted by BNFL/Westinghouse for their AP1000 reactor of US$ 1,580/kW for a first reactor and US$ 1,081 for a third of a kind unit, appear sufficiently competitive, and also achievable given the figure already attained by the reactors in China, Japan and Korea. For comparison, combined cycle gas turbine (CCGT) plants have estimated capital costs that range between US$500 and 900/kW.[190]

Caution should be exercised in judging these cost assumptions, though. The EIA points out in its Annual Energy Outlook 2004 that the estimates for reduced investment cost from nuclear vendors assume savings from building large multi-unit plants, the size of which have financial implications that cannot be overlooked. According to the EIA, there is evidence to suggest that cost overruns for earlier U.S. reactors resulted precisely from the misestimation of the savings from building large or multi-unit plants. The EIA further warns of cost estimates that are not inclusive of the costs incurred by all the parties involved in a project. The major parties involved include the construction manager, the engineering and architectural firm, the provider of the Nuclear Steam Supply System or NSSS (reactor vendor), and the utility that purchases the plant. All incur costs during the project and all of these have to be included for an accurate estimate.

[187] EIA (2004b).

[188] EIA (2004b).

[189] ANS (2002b). This last cost is not averaged to the cost of recent plants in Asia in Figure 37.

[190] Grimston & Beck (2002).

OVERALL GENERATION COSTS

The 'levelised cost' of electricity (LCOE) is used for comprehensive comparisons of different generation technologies. The levelised cost of generation is computed by adding the major components of cost in a project (capital, fuel and operation and maintenance costs), adjusting for financial costs in terms of rates of return and discounting, and finally averaging over the lifetime of the plant to obtain a value per unit of expected energy generated. Levelised cost analyses also allow evaluating the relative weight of any given factor on the overall results.

As discussed before, the structure of cost components as shown in Figure 28 gives specific characteristics to the economics of different generation projects. Nuclear power, while not responsive to variations in fuel prices as a natural gas project might be, is overly sensitive to matters that affect the investment cost component. This includes the capital itself, but also overruns on construction schedules and changes in output performance. Overruns in construction schedules would increase the interest payments on financed capital, and changes in output performance such as drops in the energy generated translate into lower revenues and increased difficulty in repaying the borrowed capital.

Also impacting nuclear plants significantly due to its high proportion of investment costs is discount rate. The effect of a raise to the discount rate on a nuclear power project compared to other sources of power generation can be seen in Table 31.

Table 31 Total levelised costs for different fuels, average of five selected countries, 1996 (1996 US cents/kWh)

Source	Costs at 5% discount US cents (1996)/kWh	Costs at 10 % discount US cents (1996)/kWh	Increase in levelised costs on moving from 5% to 10%
Natural gas	4.5	4.9	10
Coal	4.1	5.3	30
Nuclear	3.7	5.6	50

Notes: Average for Finland, France, Japan, Russia and the United States.
Source: Grimstone & Beck (2002) with data from NEA (1998).

The table shows data from the OECD NEA's latest study on the costs of electricity generation[191] which, as mentioned before, has somewhat outdated data but is still useful in showing the considerable differences in impact. It can be seen that nuclear power is competitive with coal- and natural gas-fired plants at low discount rates, but when these are raised from 5 to 10 percent the levelised cost of nuclear generation increases by 50 percent. Discount rates being applied to power projects in most developed countries have been increasing as markets have been liberalised in recent years and now stand in a region closer to 12 percent or more. More competitive commercial markets might demand rates of around 15 percent, making nuclear projects even more uneconomic compared to the alternatives.[192]

Construction time also has an important impact on the cost of capital of any type of electricity generation project. Nuclear projects are at a disadvantage not only for their higher capital costs but also for relatively longer lead times. Table 32 shows that an increase in the construction period from 6 to 10 years at a 10 percent interest rate makes the interest share in the cost of the plant grow from 29 percent to 43 percent. Vendor's estimates for construction times are generally about 36 to 48 months from the date of first concrete pour to the date of initial system testing (or fuel loading). The EIA in its *Annual Energy Outlook* 2004 estimated, based on opinions from experts, that 1 to 2 years more are required for licensing, giving a total of 6 years lead-time. And for the first units of a

191 NEA (1998).

192 Grimstone & Beck (2002).

particular type it adds 4 additional years needed to prepare an application and license, resulting in a 10-year lead-time for this type of unit.[193]

Table 32 Interest during construction and total costs per kW, based on a plant cost of US$ 1,200/kW

Construction period	Interest rate (%)	Interest cost (US$)	Total cost (US$)	Interest share of plant cost (%)
6 years	5	228.4	1,428.4	16.0
	10	497.4	1,697.4	29.3
	15	813.3	2,013.4	40.4
10 years	5	384.8	1,584.8	24.3
	10	903.7	2,103.7	43.0
	15	1,601.9	2,801.9	57.2
15 years	5	612.6	1,812.6	33.8
	10	1,596.0	2,796.0	57.1
	15	3,177.4	4,377.4	72.6

Source: Financial Times (1998).

Recent building experience in China shows encouraging results in the quest to reduce construction time. AECL's construction of the last two CANDU-6 reactor units in China, Qinshan 3 Units 1 and 2 with 728 MW each, took 51.5 and 48 months (4.3 and 4 years) respectively from first concrete pour to criticality tests. This CANDU model is closely related to the advanced ACR-700 model now being proposed by AECL. AECL, which acted as the project's main contractor, claims that by reducing the time of construction they have reduced capital costs including interest during construction by one quarter.[194]

However, unless and until a significant programme involving an advanced design has been carried out successfully, it is likely that potential investors will still regard construction time as a risk factor.

IMPACT OF FIRST-OF-A-KIND ENGINEERING

As seen in the discussion of capital costs, bringing new reactor models into market implies a need to pay for first-of-a-kind engineering (FOAKE) costs, effectively putting a premium on the cost of the first few plants. This fact alone constitutes one of the major barriers to new reactor construction worldwide. The nuclear industry together with other stakeholders have been involved in lengthy discussion over ways to overcome this potential barrier for new investments, proposing solutions ranging from governmental grants that would promote the construction of new nuclear projects, to the establishment of special mechanisms such as loan guarantees or tax breaks.

FOAKE costs refer to the engineering design specifications of a new model and the extra expenses incurred due to the construction learning process. The costs could conceivably be distributed over a large number of future reactor sales, but uncertainty in the ability to sell multiple reactors forces vendors to recover the costs on the first plants built. The magnitude and impact of FOAKE premium over new plant construction and nuclear plant economics was determined by the University of Chicago in a recent study commissioned by the USDOE to investigate major factors influencing the competitiveness of nuclear power in the United States.[195]

The study bases its comparisons in three different types of advanced reactors most likely to be built in the next decade. The first is a mature plant for which the first-of-a-kind engineering

[193] EIA (2004).
[194] CNA (2004a).
[195] UC (2004).

(FOAKE) costs have already been paid. It would resemble reactors such as General Electric's ABWR and AECL's ACR-700 and the overnight capital cost assigned to it is US$ 1,200/kWh. The second is a plant not yet built anywhere in the world for which FOAKE costs have not been paid, such as Westinghouse's AP1000. The overnight cost for this plant is US$ 1,500/kW assuming that entire FOAKE costs are covered by the first plant. To cover the high end, the third model is akin to Framatome's EPR (European advanced pressurised water reactor) that has been selected for construction in Finland. This plant is assumed to be of a more advanced design and the assigned overnight cost is US$ 1,800/kW based on estimations made in Finnish studies. Other main initial assumptions are: a plant life of 40 years, a construction time of 7 years, capacity factor of 85 percent, a 10 percent cost of debt and a 15 percent cost of equity.

The comparison of levelised cost of electricity (LCOE) figures shows that these three types of plants range from US$ 53 to 71 per MWh. A more optimistic construction period of only 5 years reduces the range to US$ 47 to 62 per MWh. The costs are for first plants constructed in the United States. (All prices in 2003 US$).

The above costs also include an additional risk premium for first new nuclear plants. Risk premiums have an important influence on the economic competitiveness of nuclear energy. Principal sources of risk are the possibilities that new plants will exceed original cost estimates and that construction delays will escalate costs. The study concludes that the first plants built of a nuclear reactor model would pay an estimated 3 percent risk premium.

Table 33 First plant LCOEs for three reactor types and 5- and 7-year construction periods (2003 US$/MWh)

Construction period	Overnight cost US$ 1,200/kW	Overnight cost US$ 1,500/kW	Overnight cost US$ 1,800/kW
5 years	47	54	62
7 years	53	62	71

In comparison, coal stands at between US$ 33 and 41 per MWh depending on fuel costs, and using overnight costs of between US$ 1,182 and 1,430/kW and its own set of construction times and interest rates in accordance with observed experience. Combined cycle gas turbine plants have levelised costs of US$35 to 45 per MWh also depending on the fuel price and using an overnight cost range of US$ 500 to 700/kW.

The study shows that shortening the construction period (as shown in Table 33) or increasing the plant capacity factor (an improvement of around 10 percent for a capacity factor of 95 percent), gives a far larger effect on levelised cost than increasing the lifetime of the plant from 40 to 60 years (which gives a minimal effect) because the benefits occur in the distant future and are discounted. Varying the debt term by 30 years also has the effect of lowering the LCOE by 10 percent. None of these changes produce costs for nuclear plants as low as the US$ 33 to 45 per MWh range of LCOEs for coal and gas-fired generation.

For the second plants, levelised power costs fall 13 to 15 percent as FOAKE costs are paid off with the first plants. After that, the construction of 8 plants in a row brings about added benefits: cost reductions from learning, reduced construction times, reduction in uncertainty and elimination of risk premiums, and increase in the debt share of financing (against more expensive equity) from resolution of uncertainties. Learning effects are accounted for by including a 3, 5 and 10 percent reduction in costs for each doubling of the number of plants completed (only results for 5 percent are shown here). For construction times, it is assumed that the financial community accepts the expectation that a third plant can be constructed in 5 years instead of the initial 7 years expected for the first two plants. The 3 percent risk premium is assumed to disappear completely (rather than gradually) for the financing of a fourth plant after the third plant has been constructed in 5 years. This would remove all uncertainty surrounding the operation of the regulatory system required for the particular type of plant and the capability to bring plants online within time and cost targets. Finally financing, which was assumed to be sourced from debt (at a 10 percent interest rate) and from equity (at a 15 percent interest rate) in equal parts for the first 4 plants, is allowed to be accomplished with a higher proportion of debt for later plants after reduced uncertainties dispelled by the successful completion of the first plants.

Depending on how these effects are combined (it can be considered that all of them take place, or that only a few of them do), nuclear plants begin to have LCOEs that are competitive to coal and gas plants after 4 to 8 plants are built. Table 34 shows how the costs for the first, fifth and eighth plants built behave with the gradual application of the different effects. The line at the top for the first plant built does not consider any of the effects except for the US$ 1,200/kW cost plant, which already has the FOAKE costs covered because it has been built previously in another country. For the fifth and eighth plants built, each successive line shows the gradual application of the different effects.

Table 34 LCOEs for successive nuclear plants, with gradual application of different effects (2003 US$/MWh)

Plant	Scenario	Initial overnight cost		
		US$1,200/kW Learning rate 5%	US$1,500/kW Learning rate 5%	US$1,800/kW Learning rate 5%
			LCOE (US$/MWh)	
First plant	FOAKE paid only on US$1,200 plant. No learning effect. Construction 7 years. Risk premium 3% Debt share of financing 50%	53	62	71
Fifth plant	FOAKE paid and accounting for learning effect	48	48	56
	Construction 5 years & elimination of risk premium	34	34	39
	Debt share of financing increased to 60%	33	33	37
Eighth plant	FOAKE paid and accounting for learning effect	47	47	55
	Construction 5 years & elimination of risk premium	34	34	38
	Debt share of financing increased to 70%	31	31	35

Results show that under not overly aggressive assumptions, a fifth new plant can deliver power at a price competitive with fossil generation. With a 5 percent learning rate, a 5 year construction period, and finance rates comparable to those of fossil plants (debt share not increased yet – see second line for fifth plant in Table 34), the three types of plant (US$ 1,200 to US$ 1,800/kW) can generate electricity at between US$ 34 and 39/MWh, comparable to fossil plants.

EFFECT OF POLICY OPTIONS TO OFFSET INVESTMENT RISKS

The University of Chicago study also explores different policy options that would offset investment risks and compensate for FOAKE costs in the first few units to encourage new nuclear investment. It analyses four types of financial policy: loan guarantees, accelerated depreciation, investment tax credits, and production tax credits.

Remembering that the study was made for the specific case of the United States, the policies investigated are as follows. A federal loan guarantee applied to say, 25 percent of the borrowed funds for capital could allow the borrowing rate on that portion of the debt to be as low as the risk free rate. Loan guarantees of 25 and 50 percent are analysed. Two accelerated depreciation schedules are examined as compared to the 15-year depreciation period specified by current United States tax laws for electric utilities: 7 years and expensing. Expensing is a common practice in European countries and refers to writing-off the entire investment cost in the first year of production. A refundable investment tax credit is modelled in the study that would allow an owner to apply the credit to the income earned from other assets if the credit is larger than the tax on the asset; like if for instance, the nuclear plant operated under a loss for the first few years and thus had no tax obligation. Ten- and twenty-percent investment tax credits are investigated. As for production tax credit, a non-payable, 7-year duration credit of US$ 18/MWh is considered in the study. This is similar in magnitude to the production tax credit applied to renewable energy in the United States. This tax credit is the same one that is being considered in legislation proposed in 2004. The study notes, however, that production tax credit helps cash flow only after the plant has been built and does not reduce near-term money requirements during construction.

The results show that no individual financial policy can be counted on to bring the LCOE of first new nuclear plants within the range of fossil alternatives. For the least cost US$ 1,200/kW plant, LCOE is reduced from the original US$ 53/MWh down to US$ 40 with a 50 percent loan guarantee. A full expensing depreciation policy can reduce it further to US$ 47. A 20 percent investment tax credit produces US$ 44. The most effective measure is an US$ 18/MWh production tax credit lasting 8 years and a cap of US$ 125 million per 1,000 MW, which would lower LCOE of the least cost plant to US$ 38 per MWh; this is in the upper range of LCOEs for coal generation.

A combination of policies, on the other hand, give promising results as shown in Table 35. The two most effective policies of an US$ 18 per MWh production tax credit with a duration of 8 years, and the 20 percent investment tax credit, are considered acting together for the figures in the table.

Table 35 Effects of combined policies on nuclear plant LCOEs (2003 US$/MWh)

	US$ 1,200/kW		US$ 1,500/kW		US$ 1,800/kW	
	Construction time		Construction time		Construction time	
	5 years	7 years	5 years	7 years	5 years	7 years
No policies	47	53	54	62	62	71
With combination of policies	26	31	31	38	37	46

LCOE of the first two types of plant for a construction period of 7 years would be in the range of US$ 31 to 38 per MWh, as compared to the range of US$ 33 to 45 for coal and gas-fired plants. If the expectation of construction times could be lowered to 5 years for the first nuclear plants, the

LCOEs of all three types of plant could be brought down to competitive levels with those of fossil plants.

Finally, environmental policies are analysed. Estimations are made to assess the impact of carbon capture and a carbon trade market on the levelised power costs of coal and gas-fired plants. The impacts are calculated on a per MWh basis and so are added to the base costs of fossil plants elevating their LCOE range farther up on the scale and negatively affecting their competitiveness with nuclear power by that same amount.

With the cost estimates available today, carbon capture and sequestration technologies would add a penalty of US$ 36 to 65 per MWh to pulverised coal combustion plants; and of US$ 17 to 29 per MWh to gas turbine combined cycle plants.

Carbon control policies are simulated through the use of a tradeable permits market. The study shows that using a lower limit price of US$ 50 per ton of carbon would produce a cost impact on coal plant LCOE of between US$ 15 and 75 per MWh; while for gas plants that impact would be between US$ 10 and 50 per MWh.

NUCLEAR POWER IN A DEREGULATED ENVIRONMENT

The advent of restructuring and deregulation in many economies of APEC and the rest of the world is another important factor to consider in the analysis of the future development of the nuclear industry. Deregulation of electricity markets is a trend expected to be followed by many economies. Open competition brings about specific implications to the economic performance of nuclear generated electricity.

The experience available with nuclear plants in restructuring markets in economies such as the United States, which owns about one-half of the installed nuclear capacity in the APEC region, has already shown some important effects. Mainly, competition has had two distinctive effects on nuclear power: first, it has been beneficial to currently operating nuclear plants; but second, up to now it has deterred new plant construction.

IMPROVED PERFORMANCE OF OPERATING PLANTS

The good performance of nuclear plants operating in electricity markets undergoing deregulation, such as has been the cases of Japan, the Unites States and other OECD economies,[196] has come as something of a surprise considering that only 5 to 10 years ago the general notion was that the industry was on its way to extinction. In the 1990s the market value of nuclear plants in the United States was at its lowest point. There was doubt as to whether nuclear plants, being more technically sophisticated compared to alternatives, could continue to operate economically in competitive conditions and could improve on their productivity without incurring in costly expenses.

Competitive pressure brought on by deregulation resulted in an increased number of mergers of investor-owned electric utilities, and this phenomenon carried over to the nuclear industry. In the United States, large companies like Exelon, Entergy, Dominion and Constellation purchased nuclear plants from regional utilities sometimes at very low prices. When plants first began to sell in 1999, transactions sold for between US$ 0 and US$ 72 per kW, and some announced transactions never took place. By 2000, two plants sold for about US$ 298 per kW. In late 2003 two transactions were announced that are expected to close in 2004: one sale at US$ 343 and another at US$ 582 per kW. (These sales prices reflect the value of tangible assets, net of nuclear fuel and intangible assets such as PPAs).[197]

The resulting specialised nuclear operators have improved productivity, shortened refuelling outages, obtained greater capacity factors, and reduced costs by optimising resources and services

[196] See the sections on United States and Japan in Chapter 1.

[197] Remsha (2004).

contracts. The market value of reactors has increased and power companies with nuclear assets have outperformed those without them in the stock market.[198]

INCREASED INVESTMENT RISK FOR NEW NUCLEAR PROJECTS

As discussed, new nuclear projects are unattractive to potential investors under the current conditions where reductions of capital investments have not been proven yet. Under the prospect of more competition brought about by electricity market restructuring, nuclear projects face increased investment risk that further deters construction of new projects.

Companies in competition require higher rates of return than those operating as monopolies because they face higher economic risks. In particular there is no longer a guaranteed market to place the project's electrical output. And also very importantly, there are no controlled prices that would ensure profitability over a pre-set term. The unpredictability of electricity rates (output price risk) under a liberalised market scheme introduces an added degree of uncertainty to the cost recovery period of any given project.

Nuclear power projects are especially affected because of their relatively higher capital costs and longer lead times. Because of competitive electricity pricing, higher capital projects take longer times to recuperate the initial investment. Thus, highly capital-intensive nuclear projects place more capital at risk and tie that capital up for longer periods of time, putting them at a disadvantage against projects that can be amortised more rapidly. This perception of added risk has investors requiring higher rates of return from nuclear projects than from others such as those powered by natural gas, thus further damaging the relative competitiveness of nuclear projects. And of course, in turn, higher rates of return are more difficult to achieve under competitive electricity pricing.

Additionally, a competitive market would be expected to have boom and bust cycles of electricity rates. If a plant is finished and starts operation under the bust part of a price cycle, it could not meet the expected levels of revenue and could have disastrous consequences for its finances.

Heavily capital-intensive projects also magnify the effects of overruns in construction costs or in time schedules (due to the interest paid on capital). Controlling these costs could therefore disproportionately reduce the risks associated with nuclear projects, and thus might help in reducing the differential between demanded rates of return for nuclear and non-nuclear projects.

The longer lead times characteristic of nuclear projects present other disadvantages in a liberalised market, aside from requiring more annual interest payments on capital. The financing of any power project requires anticipating the price of electricity after the end of construction and beginning of commercial operation, so that estimations can be made for the recovery of costs. A nuclear project with longer construction times would have to predict prices over longer periods of time introducing additional uncertainty.

DECOMMISSIONING AND WASTE DISPOSAL

Usually nuclear plants set aside funds since the beginning of their operation to cover the costs of plant decommissioning and disposal of waste. For decommissioning some countries require the establishment of a fund, managed by the government or by power generators, with annual contributions from nuclear generators usually assessed as a fixed amount per kWh of generation. In other cases, nuclear generators are required to include funding for decommissioning costs in their financial plans.

As decommissioning costs are anticipated and the funds accumulated over the life of the plant, there is uncertainty about the accuracy of the costs estimates and over the adequacy of the funds accumulated. In competitive markets, it cannot be assured that sales volumes will remain at assumed levels, which could lead to a shortfall in fund contributions. Early plant closures present another cause for concern. Shortening the life of a plant does not reduce the costs of decommissioning but will result in insufficient funds. Therefore, for nuclear plants there exists the issue of needing to

[198] Numark and Terry (2003a).

allocate financial responsibility for a shortfall in decommissioning funds in case the plant is shut down early because of policy and/or non-technical reasons.

In the case of nuclear fuel, usually the cost for its handling after it has been spent is taken into account in the cost of the nuclear fuel, and a fund is created for this activity as well. With spent fuel disposal though, the greatest uncertainty lies in the fact that in many cases no particular arrangement or technical solution has been pre-selected, making an accurate estimation of costs difficult. Another uncertainty lies in obtaining the legal approvals for the implementation of the eventual waste disposal solution. In some countries, nuclear generators await a policy decision on waste to create a fund.

This large potential liability stands as a strong deterrent for future private capital investment in nuclear power. Financial institutions will not invest in operations that have undefined and unsecured liabilities of such potential magnitude.

How this issue is resolved depends on how each economy defines liabilities for the disposal of high level waste. The issues include how the governments assign legal responsibility for waste disposal and the degree of responsibility it will assume, including financial responsibility. The establishment of adequate funding and the correct apportioning of liabilities will be resolved only after an accurate appraisal of the costs of plans and infrastructure for the handling of waste can be made. And for that, policy decisions have to be made regarding the technical solution to be given to the final handling of waste.

It is important to assess the real impact of waste and decommissioning costs to total costs. Two recent analyses point out that the real magnitude of the impact is relatively small, and therefore so is the impact on the perceived risk added to new plant investment.

According to Grimston and Beck (2002), rising costs of the back-end of the fuel cycle including waste disposal, reprocessing and decommissioning, technically do not affect the calculations of levelised costs for plants to be commissioned between 2005 and 2010, as these costs include estimates for the back-end costs based on current best assessments. Also, as these costs are incurred late in the investment cycle for the project, their discounted value accounts for only a small proportion of the total levelised costs, typically less than 10 percent. A problem could arise if back-end costs continued increasing after the plant starts operating. As the life of the plant evolves, those increased costs could not be easily accommodated as the period over which the extra funds can be raised is shorter the nearer the end of the plant's life is. However, this can be offset to an extent by the trend to extend the life of nuclear reactors.

Another assessment is found in the University of Chicago study which includes as one of its conclusions that the plausible differences in fuel cycle cost are not a major factor in the economic competitiveness of nuclear power. The cost of direct disposal of spent fuel including the cost of on-site storage plus the contribution to a fund for the eventual permanent disposal at a centralised site, as is the policy adopted in the United States, has a cost of about US$1.1 per MWh. This contributes only about 2 percent to the overall LCOE.[199]

STRANDED COSTS

Stranded costs are investment expenses and other obligations incurred by a utility that cannot be recovered due to insufficient level of revenue such as what would occur with lower electricity prices in a competitive market. Stranded costs result in part from business and investment decisions on the part of utilities, but they also result from the costs of mandated public interest programmes such as energy efficiency, assistance to low-income customers, or power purchase agreements that force utilities to pay premium prices for the electricity of independent producers. For nuclear facility owners, it also includes the cost of setting aside a fund for plant decommissioning and waste disposal.

The transition to competitive markets brings about the possibility of excessive accumulation of stranded costs, putting utilities at financial risk. It also places utilities with stranded assets at a

[199] UC (2004).

competitive disadvantage against new independent generators. A solution to this issue is therefore something that requires consideration in preparation for the introduction of a deregulation scheme.

Decommissioning and spent fuel handling obligations are unlike other stranded costs in that the funding required for these activities are not sunk costs, but expenses that have to be made in the future. Unfunded decommissioning and waste liabilities represent a significant portion of the United States electric industry's stranded costs. Moving into restructuring there is concern that decommissioning and waste obligations might not be adequately funded. Defining mechanisms to ensure the collection of unfunded obligations has to be considered an integral part of any transition to a competitive electricity market. One factor that lessens the risk is that competitiveness of nuclear plants in terms of operating costs reduces the threat of premature closure and therefore also reduces the possibility of under-funding of decommissioning and waste costs.

Nevertheless a number of economies have recognised the need for a mechanism to allow for some form of cost recovery, and in some cases have already allowed it. The European Union Electricity Directive recognises the need for transitional costs. The Spanish electricity restructuring law made arrangements for stranded assets.[200] In the United States, where each state is free to determine whether deregulation is in their best interest, many states that passed legislation to restructure their electric industry have allowed utilities to recover stranded costs over a limited period of time through a surcharge on customers. In some cases companies have also elected to accelerate depreciation of their investment in power plants. Companies that accelerate depreciation suffer a short-term earnings penalty, but the faster write-down leaves them better positioned for future competition.

Not all markets making the transition from monopoly to competitive generation will necessarily have stranded costs. This has been the case of Finland, the Netherlands and Sweden. In France, where the process to open the electricity market to competition has started, but where the electricity sector is still dominated by the state owned Electricite de France, evaluations by this utility indicate there would be no stranded nuclear assets.[201]

In the United Kingdom the Fossil Fuel Levy, a fixed percentage charged on all electricity sold, was introduced to reimburse utilities for the obligation to purchase electricity from non-fossil sources at premium prices. The levy included a portion to fund nuclear plant decommissioning and waste disposal expenses, and this nuclear portion was discontinued in 1996 with the privatisation of British Energy and the recognition that by that time nuclear power was fully competitive.[202]

CONCLUSION

Nuclear energy has not yet achieved the kind of costs that will allow it to compete favourably with other forms of baseload capacity. For nuclear energy to be considered as a possible widespread choice for electricity generation, the nuclear industry has to offer an economically attractive product not counting on any benefits achievable through external costs, nor subsidy, nor the weakening condition in the pricing of alternate fuels.

Nonetheless there are promising indicators that point to the possibility of such thing happening in the near future. In part the renewed interest in nuclear power today stems from this possibility. The unanticipated good performance of nuclear plants in markets undergoing restructuring has made governments and utilities re-analyse the prospects of nuclear power as a viable source of electric power. Nuclear plants currently in operation are economically attractive. With fuel prices that are lowest compared to fossil fuel alternatives and operation efficiency records that continue to improve, they have become in many places the least operating cost option for baseload capacity. They also

[200] NEA (2000).
[201] IEA (1998).
[202] NEA (2000).

offer predictability in fuel costs that no fossil fuel plant can provide. Witness the price of natural gas that has doubled in the United States between 2003 and 2004.[203]

But as noted, the competitiveness of nuclear power rests on the ability to reduce investment costs. Capital costs have to come down. Advanced reactor models promise lower investment costs and shorter construction times, but the nuclear industry still has to demonstrate that it can finish projects on time and under budget, and new licensing processes (in those economies where they have been implemented) have to be tested. The recent construction record in APEC economies in Asia is on the right trend towards bringing investment costs and construction schedules under control.

Still, the construction of the first few new units will bear large costs and risks. The study commissioned by the DOE to the University of Chicago shows that under reasonable and achievable circumstances, it takes the construction of 5 plants for a new model to start producing electricity competitively against fossil plants. It is possible to control the costs of the first five units built (reduce the impact of first-of-a-kind-engineering costs) and bring them down to competitive levels by a using both production tax credits and investment tax credits, and by keeping construction times down to 5 to 7 years at the most.

And another option to bear the costs and risks of the first few plants, and probably the key for future nuclear orders, is the formation of consortia willing to commit to the construction of several plants. The need for one entity to bear the risks of a first plant alone can be eliminated by averaging the costs of more than 5 plants (something like 8) among a group formed by reactor vendors, financial institutions and a few utilities, without having to resort to any additional assistance from governments. Large nuclear consolidators such as Entergy, Exelon, Dominion, and Constellation are probably better positioned to achieve something along those lines. In fact, some of these consortia have already proceeded with pre-licensing work and applied for early site permits to the Nuclear Regulatory Commission in the United States.

[203] NEI (2004c).

CHAPTER 4

RESOURCES AND DEPLETION OF NUCLEAR FUEL MATERIALS

INTRODUCTION

Aside from the contributions to sustainability that nuclear energy can provide, there is a rather different type of sustainability that has to be assessed: whether there are enough resources in the world for nuclear power to sustain itself as a major source of electricity well into the future. To examine this sustainability, it is necessary to understand the real magnitude of existing resources and the different ways and rates at which the resources are consumed for the production of electricity (the demand that nuclear energy places on them).

Two types of naturally occurring materials can be used as fuel for nuclear reactors: uranium and thorium. In addition, other materials that do not occur naturally are produced during the operation of a reactor, like plutonium, and can be recovered from burned-up fuel to produce fresh fuel and effectively extend the total amount of available resources.

Apart from the newly mined and processed uranium or primary supply, there is presently also a large base of uranium available in what is called 'secondary supply', made up of highly enriched uranium (HEU), natural and low enriched uranium inventories, mixed oxide fuels (MOX), reprocessed uranium, and re-enrichment of depleted uranium or 'tails'.

URANIUM

Uranium resources are classified according to the degree of their geological assurance and the economic feasibility of their recovery. The OECD's Nuclear Energy Agency together with the International Atomic Energy Agency in their biennial report on the world's uranium reserves[204], define 4 categories according to the confidence levels of occurrence. Reasonably assured resources (RAR) occur in known mineral deposits of delineated size, grade and configuration and can be recovered within given cost ranges with currently existing mining and processing technology. Estimated additional resources-Category I (EAR-I) are resources that are inferred to occur based on direct geological evidence in extensions of well-explored deposits or in deposits where geological continuity has been established. Category II of estimated additional resources (EAR-II), are expected to occur in deposits for which the evidence is mainly indirect and which are believed to exist in well-defined geological trends or areas of mineralisations with known deposits. Speculative resources (SR) are resources that are thought to exist mostly based on indirect evidence and geological extrapolations in deposits discoverable with existing exploration techniques. Their location can only be characterised as being somewhere within a given region or geological trend. In general terms, while reasonably assured resources and EAR-I include known or delineated resources, EAR-II and speculative resources have yet to be discovered.

A further categorisation is required to reflect differences in the recovery costs of resources. The cost of recovery depends on both the quality of the resource and on mine-operating costs. NEA/IAEA (2004) uses US$40/kilogram of Uranium (kgU), US$80/kgU and US$130/kgU.

With the current uranium price and the variation in price expected in the near- to medium-term future, economically recoverable proved reserves can therefore be considered to be the sum of

[204] NEA/IAEA (2004).

reasonably assured resources and estimated additional resources-Category I recoverable under US$130/kg. The sum of RAR and EAR-I is what is referred to as known conventional resources. As shown in Table 36, proved reserves of uranium in the world as of January 2003 are close to 4.6 million tonnes according to the NEA/IAEA report. It should be noted that this total covers only the quantities reported by the responding countries to the mentioned report's survey, and that even further unreported quantities might also exist. The figures listed refer to in situ quantities, i.e. the total resources existing in the ore as opposed to the quantities that can actually be recovered because of losses within the process.

The economies in the world with the largest proven reserves are, in order: Australia, Kazakhstan, Canada, South Africa and the United States. APEC economies that reported resources to this survey own over 2 million tonnes of these proved reserves. APEC economies Australia, Canada, the United States and Russia account respectively for 23, 10, 8 and 6 percent of the world's total. Canada is the world's largest year-on-year producer of uranium. In 2002, its production amounted to one-third of the world's total and is followed by Australia, with about half as much.[205]

Table 36 APEC known conventional resources and World total, as of January 2003 (Thousand tonnes of uranium)

Economy	Reasonably assured resources (RAR)		Estimated additional resources Cat. I (EAR-I)		Total known conventional resources
	<US 80/kgU	<US 130/kgU	<US 80/kgU	<US 130/kgU	
Australia	702.0	735.0	287.0	323.0	1,058.0
Canada	333.8	333.8	104.7	104.7	438.5
Chile (c) (d)	NA	0.6	NA	0.9	1.5
China (c)	35.1	35.1	14.7	14.7	49.8
Indonesia (b) (c)	0.3	4.6	0	1.2	5.8
Japan (b)	NA	6.6	NA	NA	6.6
Mexico (a) (b) (c)	0	1.3	0	0.5	1.8
Peru (c)	1.2	1.2	1.3	1.3	2.5
Russian Federation (c)	124.0	143.0	34.3	121.2	264.2
Thailand (a) (c)	0	0.01	0	0.01	0.01
United States	102.0	345.0	0	0	345.0
Vietnam (c)	NA	1.0	0.8	5.4	6.4
APEC total	1,298.4	1,607.2	442.8	572.9	2,180.1
World total	2,458.1	3,169.2	1,078.8	1,419.5	4,588.7

Notes: a From previous Red Book.
b Assessment not made within last 5 years.
c Secretariat estimate.
d Cost data not reported, therefore resources are reported in the <US 130/kgU category.
Source: NEA/IAEA (2004).

Table 37 lists APEC's and the world's total EAR-II and speculative resources categories. EAR-II estimated to be recoverable below US$130 per kg of uranium add an additional 2.3 million tonnes of uranium and speculative resources add at least 7.5 million tonnes of resources around the world. More speculative resources exist on earth as those numbers listed reflect only the resources from 28 reporting countries. For instance, Australia is thought to have significant amounts of undiscovered uranium, both EAR-II and speculative resources, but it does not perform evaluations of such materials and therefore are not listed on the table.

[205] WNA (2003c) and (2003d).

Table 37 APEC undiscovered uranium resources and World total, as of January 2003 (Thousand tonnes of uranium)

Economy	Estimated Additional Resources Category II		Speculative Resources		
	Cost ranges		Cost ranges		
	<US 80/kgU	<US 130/kgU	<US 130/kgU	Unassigned cost	Total
Canada	50.0	150.0	700.0	0	700.0
Chile	NA	2.3	NA	2.4	2.4
China	3.6	3.6	4.1	0	4.1
Indonesia	0	0	0	4.1	4.1
Mexico (a)	NA	3.0	NA	10.0	10.0
Peru	6.6	6.6	19.7	0	19.7
Russian Federation	56.3	104.5	545.0	0	545.0
United States (b)	839.0	1,273.0	858.0	482.0	1,340.0
Vietnam	0	7.9	100.0	130.0	230.0
APEC total (reported by economies)	955.5	1,550.9	2,226.8	628.5	2,855.3
World total (reported by economies)	1,474.6	2,254.5	4,437.3	3,102.0	7,539.3

Notes: a Data from previous Red Book.
b USA reports all EAR-I and EAR-II as EAR-II.
Source: NEA/IAEA (2004).

The availability of secondary supply including HEU, inventory draw down, recycled uranium and plutonium, and re-enrichment of depleted tails from enrichment has limited demand of newly produced uranium and has had an impact on production projects preventing expansion in some cases and exerting a downward pressure on the price of uranium for a number of years. Secondary supply accounted for around 40 percent of reactor demand in 1998.[206] Primary supply is expected to become the dominant supply source as the material making up the secondary supply is drawn down to strategic levels or depleted altogether. The IAEA estimates that by 2025 secondary supply will only account for between 4 and 6 percent of uranium demand.[207]

HEU is uranium material that has been highly enriched for defence programme purposes for use in weapons manufacture and in reactors for naval propulsion and research. Over half of the historical production of uranium has gone into producing fissile materials for government national defence programmes in several countries. After the successful completion of arms reduction treaties between the United States and the former Soviet Union, large quantities of HEU and plutonium in these and other economies were declared as surplus for defence purposes and are now being converted to commercial reactor fuel.

The natural and low enriched uranium referred to here is the material held in commercial inventories in a number of western countries and the inventory held in the Russian Federation. The western materials are the strategic and discretionary inventories created to avoid disruptions and guarantee fuel manufacture lead times, and the Russian Federation stockpiles are the result of an overproduction of military and civilian requirements. Some of the HEU and low enriched uranium inventories resources in Russia and other countries are not well known, making it difficult to assess their impact on the total extent of the reserves of reactor fuel material.

[206] IAEA (2001).
[207] IAEA (2001).

While the most common nuclear fuel is made up of uranium dioxide, MOX fuels use a mixture of uranium and plutonium dioxides. Plutonium is a product of the uranium burn-up inside a reactor and together with unburned uranium is recovered from reprocessed fuel to be recycled as fresh fuel. Eight economies have established reprocessing-recycling programmes: Belgium, China, France, Germany, Japan, Russia, Switzerland and the United Kingdom.

The stockpiles of depleted uranium, or 'tails', are a by-product of the uranium-enriching process. For each kg of enriched uranium produced, an average of 8 kg of depleted uranium is also produced. Non-fuel uses of this material involve only relatively small amounts. Fuel uses include mixing with plutonium in MOX fuel or for dilution of HEU. Re-enrichment to further obtain more reactor grade uranium becomes feasible if the ratio between the enrichment unit cost and natural uranium prices allows such recovery. Re-enrichment of depleted uranium to produce reactor fuel has taken place in the Russian Federation for several years.[208] It is expected that such use for depleted uranium will have a greater impact in the future as the price of uranium resources tends to increase.

The OECD's Nuclear Energy Agency estimates that the equivalent amounts of uranium from secondary supply sources such as those detailed above, total around 600 ktonnes coming from HEU and recycled plutonium plus another 200 ktonnes from uranium stocks and the other sources.[209]

Still more uranium can be found in what are known as unconventional resources. These are essentially low concentration occurrences with higher recovery costs that can be tapped into if uranium demand should increase in the future. The existing supplies of unconventional resources exceed by far those of known conventional resources. Some of these include phosphate deposits in sedimentary rocks with uranium concentrations of about 100-200 parts-per-million (ppm) that can exceptionally run as high as 1000 ppm in igneous rocks. High uranium concentrations have also been found in black shale deposits and in granite rocks. It is estimated that as much as 22 million tonnes of uranium can be recovered from phosphates.[210]

Seawater contains vast amounts of uranium in low concentrations of around 3 parts per billion that can fuel nuclear reactors indefinitely into the future. As much as 4.2 billion tonnes of uranium are estimated to exist in seawater, or 700 times the known conventional resources.[211] Research work in France and Japan has shown that uranium can be recovered from seawater at a cost of between US$80 and 100, although it is not known for sure how much the prices would be affected by scaling up the processes to industrial size.[212]

THORIUM

Thorium is another naturally occurring element that can be used as fuel in nuclear reactors. Thorium is about 3 times more abundant than uranium in the earth's crust. One important feature is that all of the mined thorium is potentially usable in a reactor, as compared to only 0.7 percent of naturally occurring uranium. As a result, thorium can have as much as 40 times the amount of energy per unit mass as natural uranium.

Data from the U.S. Geological Survey shows the existence of 1.2 million tonnes of economically extractable thorium reserves in 1999.[213] Expanded use of thorium commercially as fuel for nuclear reactors can go a long way in extending the lifetime of nuclear fuel resources. Initial interest in thorium use has waned out in most countries partially as a result of relatively low uranium market prices, making investments in further thorium research futile for the time being. However, enough experience has been gained in thorium use so as to give confidence in the possibility of its widespread

208 NEA (2001).
209 NEA (2001).
210 NEA (2001).
211 NEA (2001).
212 UNDP (2000).
213 WNA (2003b).

use without the need for major technological breakthrough work. India is a country that is committed to developing the thorium fuel cycle given that it owns more thorium than uranium resources.

Table 38 Worldwide reserves of thorium, 1999 (Tonnes)

Economy	Reserves (tonnes)
Australia	300,000
India	290,000
Norway	170,000
USA	160,000
Canada	100,000
South Africa	35,000
Brazil	16,000
Other countries	95,000
World Total	1,200,000

Source: US Geological Survey, 1999.

DEPLETION RATE OF NUCLEAR FUEL RESOURCES

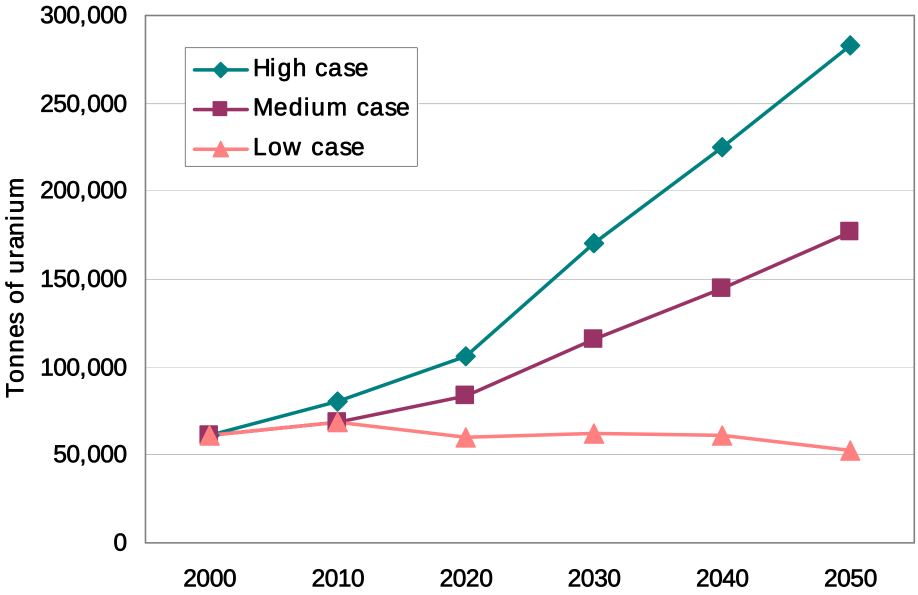
The study *Analysis of Uranium Supply to 2050* [214] by the IAEA evaluates the adequacy and reliability of uranium supply to meet the demand of projected power reactors around the world in the next 50 years. That study analyses 3 possible scenarios for demand: low, middle and high demand cases. To project uranium requirements for the first period from 2000 to 2020, IAEA used its own estimates based on every country's nuclear power programmes and plans. It assumes that all plans are implemented for the high case, while the lower estimates foresee reactor closures at the earliest dates and cancellation or deferral of new reactors. For the rest of the period from 2020 to 2050, IAEA selected scenarios from *Global Energy Perspectives*, a study published jointly by the International Institute for Applied Systems Analysis and the World Energy Council.[215] The IIASA/WEC scenarios chosen are:

- High demand case.- (IIASA/WEC A3 scenario). Corresponds to high economic growth, limited impact of environmental concerns on energy policies and significant development of biomass and nuclear power.
- Middle demand case.- (IIASA/WEC C2 scenario). Corresponds to medium economic growth, ecologically driven energy policies and sustained development of renewable energy sources and nuclear power worldwide.
- Low demand case.- (IIASA/WEC C1 scenario). Corresponds to medium economic growth, ecologically driven energy policies and phase-out of nuclear power worldwide by 2100.

Figure 38 shows the three demand cases considered in the IAEA study. For the high demand case, requirements would total 283,000 tonnes of uranium in 2050 and the cumulative requirements from 2000 to 2050 would amount to 7.6 million tonnes of uranium. In the middle case scenario the requirements in 2050 would total 177,000 tonnes of uranium with the cumulative demand equal to 5.4 million tonnes. The low case would need 52,000 tonnes of uranium in 2050 and the cumulative requirement would sum 3.4 million tonnes.

[214] IAEA (2001).
[215] IIASA/WEC (1998).

Figure 38 IAEA projections of annual uranium requirements, 2000-2050 (Tonnes of uranium)



Source: IAEA (2001).

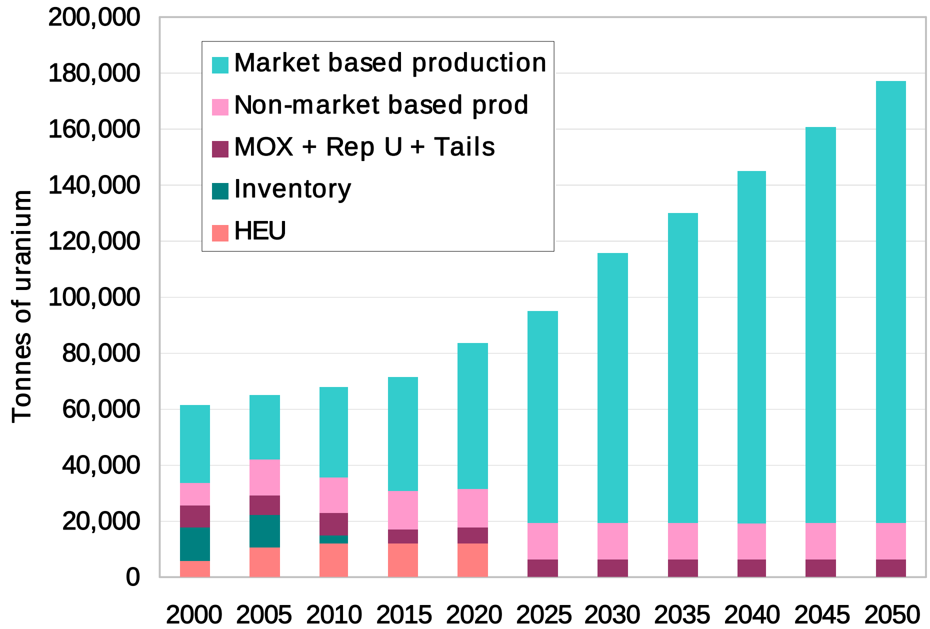
The study then goes on to analyse the way in which this demand is fulfilled by the different types of supply sources available. Primary supply in the study is divided into one fraction that is not constrained by market conditions, and a fraction of production that is. Placed under the category of unconstrained market conditions is the production coming from the Commonwealth of Independent States (CIS), from China and from several national programmes, such as those in Argentina, Brazil, Bulgaria, the Czech Republic, France, Germany, Hungary, India, Pakistan, Romania and Spain. This production is mostly dedicated to meeting domestic reactor requirements and continues to be produced despite the higher production costs either because of their importance to the local economy or for reasons of national security. The study assumes that the present level of production of non-market constrained material is maintained throughout the period and that any increase in requirements will either be produced competitively or purchased in the open market. Either way obtained from market production, in other words.

The IAEA's study methodology calls for fulfilling the projected requirements first with supply from secondary sources and from market-unconstrained primary production. It then focuses on determining the adequacy of the different types of market-based production in meeting the remaining requirements: low and high cost reasonably assured and estimated additional resources, and speculative resources.

In terms of secondary supply, it is considered that such source covered 42 percent of total demand in the base year 2000. The contribution drops to 6 and 4 percent of demand by the year 2025 in the middle and high demand cases, respectively, and the percentage continues to decline until 2050. In total, secondary supply is found to contribute about 11 and 8 percent of cumulative demand to 2050 in the middle and high demand cases, respectively.

Non-market based production accounted for 12 percent of the total requirements in the base year 2000. The production plans in a number of these programmes is projected to increase somewhat in the following years increasing the participation of non-market production to close to 20 percent by the year 2010 in the middle case and to around 17 percent in the same year in the high case. After that, as estimated by the study group of consultants, non-market based production will tend to stabilise as any additional needs in internal demand would be satisfied by either competitive domestic production or by purchases in the uranium production market. The result is that non-market production would amount to around 8 percent of total requirements by 2050 in the middle case, and to around 5 percent in the high case.

Figure 39 Sources of uranium supply for projected demand 2000-2050, middle demand case (Tonnes of uranium)



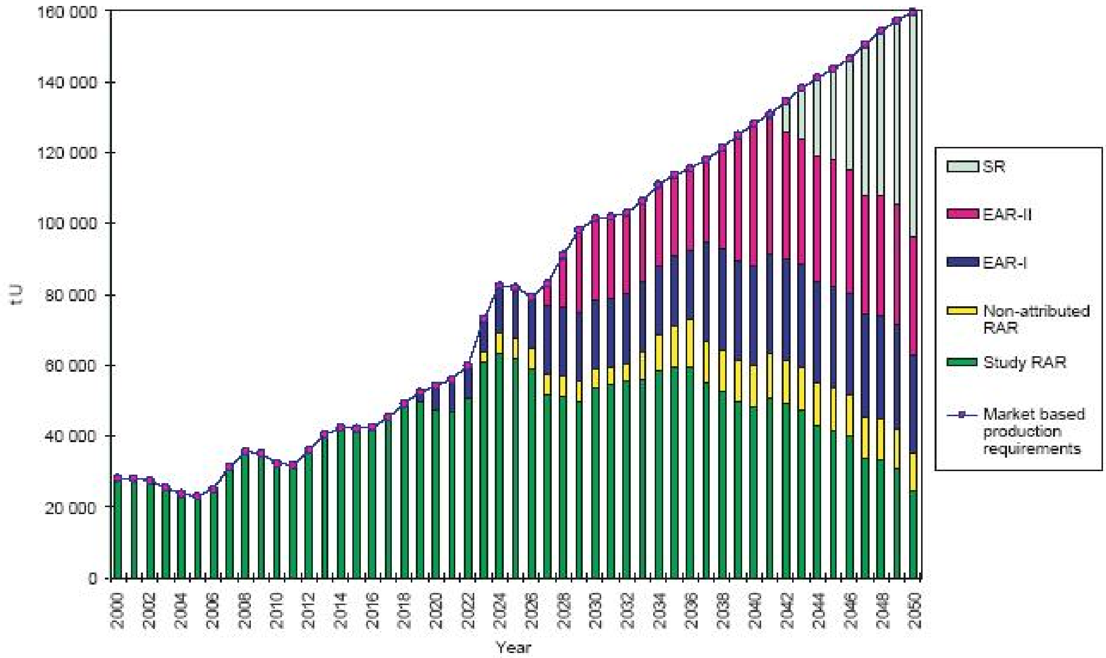
Source: IAEA (2001).

Market-based production covers 46 percent of uranium requirements in 2000 in the middle demand case; and grows to 86 percent by 2025 and to 90 percent by 2050. For the high demand case, market based production starts by covering 45 percent in 2000 and increases to 92 percent by 2025 and around 94 percent by 2050. Market based production satisfies 77 percent of cumulative demand between 2000 and 2050 in the middle case, and 85 percent in the high case. The graph in Figure 39 summarises these tendencies and shows the growing importance of market-based production share in the latter years of the 50-year period.

Reasonably assured resources (RAR) with a high assurance of existence are adequate to fulfil the market-based requirements (uranium requirements after secondary resources and non-market resources have been subtracted) in the low demand case. This is basically the notion expressed in various publications where known resources are said to be capable of sustaining nuclear energy for more than 50 years at the present rate of consumption. Although it provides a point of reference, the statement does not illustrate the implications a consumption higher than the present rate will have over the cost of uranium production. For the middle and high demand cases, RAR are not sufficient to cover market-based requirements.

The total market-based requirements for the 50-year period are 4.2 million tonnes of uranium in the middle demand case and 6.4 million tonnes in the high demand case. Figure 40 shows for the middle case how market-based production is satisfied first with high assurance resources and how gradually other resources with lower confidence levels and at the same time higher production costs are called in to fulfil demand.

Figure 40 Contribution by resource category to market-based production requirements 2000-2050, middle demand case (Tonnes of uranium)



Source: IAEA (2001).

As shown in Table 39, when only RAR are taken into consideration, there is a deficit in the whole 50-year period of 1.5 million tonnes of uranium in the middle demand case that increases to 3.7 million in the high demand case. Even when estimated additional resources categories I and II (EAR-I, EAR-II) are added, there still exist deficits of 306 thousand tonnes in the middle case and of 2 million tonnes in the high case. It should be noted that projected production in the table is not equal to total existing resources. Not all known resources are available for extraction in the 50-year period study; some have higher extraction costs and their extraction is deferred for a future time when market prices justify the production costs.

Table 39 Comparisons between market-based requirements and resource availability 2000-2050, middle and high demand cases (Tonnes of uranium)

	Middle demand case	High demand case
RAR		
Market base production requirements	4,158,280	6,406,190
Cumulative projected production	2,617,860	2,672,390
Deficit	(1,540,420)	(3,733,800)
RAR + EAR-I		
Market base production requirements	4,158,280	6,406,190
Cumulative projected production	3,313,780	3,455,840
Deficit	(844,500)	(2,950,350)
RAR + EAR-I + EAR-II		
Market base production requirements	4,158,280	6,406,190
Cumulative projected production	3,851,530	4,346,270
Deficit	(306,750)	(2,059,920)

Source: IAEA (2001).

The deficit of market-based requirements would have to be satisfied with speculative and/or with unconventional resources, with a high degree of uncertainty as to the cost of production associated to those.

IMPACT ON PRICE

The influence of secondary supply inventories in existence today are such that uranium market price does not reflect actual production costs. That is bound to change in the future as secondary supply becomes less and less important. In addition to that, new harder to find and produce resource categories will be gradually needed to cover the rising demand, increasing extraction costs and having a more direct impact on the costs of fuel. Table 40 is an indication of market price trends for uranium in the future and shows this effect. It shows, under various combinations of resource categories used to cover demand, the year when market prices are projected to break into the next higher cost category.

Table 40 Years when higher cost production first becomes justified, middle and high demand cases

	52-78 US$/kg	78-130 US$/kg	>130 US$/kg
Middle demand case			
RAR	2019	2024	2028
RAR + EAR-I	2021	2027	2034
RAR + EAR-I + EAR-II	2021	2029	2041
High demand case			
RAR	2013	2019	2023
RAR + EAR-I	2015	2022	2026
RAR + EAR-I + EAR-II	2015	2023	2031

Source: IAEA (2001).

In the middle case, if production is limited only to known resources RAR and EAR-I[216], it is projected that resources with production costs of more than US$52/kg of uranium will be needed to fill market-based requirements in 2021, therefore increasing the spot market price to that level. Spot market price would then increase to the following level of more than US$78/kg of uranium in 2027. However, if EAR-II category resources at the lower side of the cost scale were to be also considered, therefore allowing more low-cost resources to be used in fulfilling demand and with the implication that the necessary exploratory and evaluation development work would have been made well in advance, then the move of spot prices to the US$78/kg level would happen two years later, in 2029. In the high demand case, spot price of uranium would surpass the US$130 per kg of uranium by the year 2031 when the three categories of resources are considered.

Speculative resources reported by participating countries to the 2003 Red Book[217] total 7.5 million tonnes of uranium. Of those, 4.4 million tonnes are estimated to be recoverable at less than US$130/kg. Theoretically, therefore, enough resources costing less than US$130/kg of the speculative kind exist to cover the market-based requirements up to 2050 even in the high demand case (the deficit is just over 2 million tonnes of uranium, Table 39). Caution should be taken when considering speculative resources, though. There are degrees of credibility as to the reported speculative quantities, and a percentage of those might not be produced at the expected costs. On the other hand, the list of speculative resources in the Red Book is incomplete, with only 28 countries reporting this type of resources compared to a total of 43 countries that reported other types of resources to this publication. Still, converting those resources to viable ones requires extensive

[216] RAR and EAR-I are both known resources, as explained earlier.

[217] NEA/IAEA (2004).

exploration and expenditures and they must be converted to discoveries early enough to ensure that the resulting material will be available before the end of the 50-year period. Additionally, the incentive of high, sustainable market prices must exist to support exploration and development risks and expenses.

CONCLUSION

In conclusion then, speculative resources at production costs of under US$130/kg are adequate to meet both the middle and high demand case requirements for the next 50 years. Unconventional resources constitute large additional, but costlier, uranium resources. As mentioned in the section on uranium, estimations by the NEA[218] place resources of uranium in phosphates at around 22 million tonnes and uranium in seawater at around 4.2 billion tonnes. As a point of reference, the same publication estimates that uranium in phosphates could last for 440 years at the present rate of consumption, while that in seawater could last for as long as 80,000 years.

Thorium resources are also technologically accessible and can contribute in a tangible way to cover a fraction of reactor fuel requirements in the future. The importance of thorium as an alternative fuel should not be underestimated in a scenario of accelerated nuclear power demand with fast depletion of uranium resources imposing upwards pressures on market prices. Consider that present day available thorium resources of 1.2 million tonnes provide 40 times the energy of a similar quantity of natural uranium and it will be easy to see that the downward impact on prices would not be insignificant.

Availability of resources in the long term is therefore not to be questioned. Rather, the question is what will the depletion rate be (which fuel cycles become popular), what type of resources will have to be tapped into and what impact will that have on the price of fuel. Given the considerations of the literature cited, it appears that at least during most of the 21st century fuel will be available to fission reactors at relatively acceptable prices. One hundred years from now, nuclear fission should be giving way to other, more advanced energy transformation technologies.

[218] NEA (2001).

CHAPTER 5

WASTE MANAGEMENT

INTRODUCTION

The management and disposal of radioactive wastes has been one of the most controversial aspects of nuclear power. Among the general public there exists the notion that this is as yet an unresolved issue incapable of being solved by the nuclear industry. As we shall see this is not exactly the case and there are solutions available and proven for the disposal of every type of radioactive waste. This is true even for the case of the permanent disposal of long-lived wastes, for which there already exists a repository in operation in the United States.

This chapter describes briefly the present situation of nuclear waste management and the status of waste technology. The specifics about the waste management policies in each APEC economy has been detailed in Chapter 1: *Nuclear Policies in the APEC Region*. In this chapter we also summarise the international approach to waste management and comment on possible areas for collaboration among APEC members.

ASSESSING THE NUCLEAR WASTE CHALLENGE AND AVAILABLE SOLUTIONS

The operation of nuclear power plants brings with it the production of wastes, as any other industrial or energy related activity. However, the wastes produced do not pollute the environment, as virtually all the wastes are strictly contained and managed. Nuclear power is the only energy-producing industry that takes full responsibility for all its wastes and factors in the costs of their handling into the final product. In economies with nuclear power plants, nuclear wastes comprise less than 1 percent of the total industrial toxic wastes produced. Radioactive waste differs from other categories of industrial waste in that it becomes less dangerous and decays to harmless radiation levels over time. Toxic industrial wastes are much more voluminous, present similar difficulties for their disposal and remain at the same level of toxicity forever.

The wastes produced by nuclear plants can be of two types: Low and Intermediate Level Radioactive Waste (LILW) and High Level Radioactive Waste (HLW). Low and intermediate level waste contains enough radioactivity that it requires actions to ensure the protection of workers or the public for short or extended periods of time. It includes a range of materials from just above exempt levels to those with sufficiently high levels of radioactivity to require use of shielding containers and in some cases cooling off periods. The wastes consist mainly of debris and litter from routine facility operations and the claddings of used reactor fuel. There is little heat output from these wastes, although it sometimes requires remote handling. These wastes can be subdivided further according to the half-lives of the radionuclides they contain into: *short-lived* with half-lives less than 30 years and *long-lived* greater than 30 years.

High level waste comprises the spent fuel itself or the highly active material resulting from the reprocessing of the fuel. It contains such high levels of radioactive materials that a high degree of isolation from the biosphere is required for long periods of time, normally a geologic repository. The largest part of the radioactivity derives from the *fission products* within the waste, most of which have half-lives of less than 1,000 years. The other components of high level waste are long-lived elements known as *actinides* which have comparatively less radioactivity than fission products but half-lives that can extend over a thousand years.

A typical 1,000 MW nuclear reactor produces in a given year approximately 300 m^3 of LILW and some 30 tonnes of high-level solid waste. At present, the world's commercial nuclear power reactors produce in general terms a total of 40,000 tonnes of radioactive wastes per year, all of it managed and accounted for. This waste consists of 15,000 tonnes of spent nuclear fuel, or HLW, and 25,000 tonnes of LILW.[219]

APEC, owning close to 54 percent of the world's power reactors, produces approximately 22,000 tonnes of radioactive waste per year, consisting of 14,000 tonnes of LILW and 8,000 tonnes of HLW. The volume of the low level wastes produced in a year in APEC can fit in a space measuring 30 meters X 30 meters X 15 meters, or about the size of a small warehouse or supermarket. The volume of APEC's spent fuel for a year is around 1,100 cubic meters, or about the size of a small single-level house.

Owing to the amount of nuclear plants that they have, economies such as Finland, the Netherlands and Switzerland have produced *reference designs* for planned final repositories with enough capacity to hold the wastes produced by the generation of 1,000 TWh of electricity. Others like Belgium, Germany, Spain, Sweden and the United Kingdom have reference designs for an equivalent of 1,000 to 10,000 TWh. France has the largest reference design capable of holding the wastes equivalent to 25,000 TWh of nuclear generation.[220] The Yucca Mountain project in the United States has a capacity of 70,000 metric tonnes, equivalent to 15,000 TWh.

At the current levels of power produced in APEC by nuclear plants of around 1,400 TWh per year, no more than one facility of the scale of the United States' reference design would be required for the whole region every 10 years. However, if nuclear generation were to expand 3 times to around 4,000 TWh per year, as predicted by our own projections in the Moderate Nuclear Development Scenario (see Chapter 6: *Alternative Nuclear Power Futures in APEC*), then the high level wastes produced in the whole of APEC would require the construction of one facility of the scale of the Yucca Mountain Project every 4 years or so.

Waste to be produced in nuclear operations from now on will be smaller in quantity per unit of electricity generated than has historically been the case, partly because of advances in reactor and fuel technology, and partly because much of the wastes produced up to now include significant volumes that were produced in early research and military programmes.

LOW AND INTERMEDIATE LEVEL WASTE MANAGEMENT

LILW accounts for a little less than 90 percent of all radioactive wastes. Short-lived LILW are often treated for volume reduction using chemical precipitation, incineration or compaction. Wastes are afterwards conditioned for containment and immobilisation in materials such as concrete, bitumen or polymers. The wastes are then isolated for periods of up to 300 years (approximately 10 times the half-life) in near-surface disposal facilities or shallow geologic repositories.

About 40 near-surface disposal facilities exist worldwide and have operated safely during the past 35 years. Thirty facilities more are expected to be in operation over the next 15 years. Experience exists in every stage of construction and operation of LILW near-surface disposal and shallow geologic repository; and all engineering aspects of the technology are dominated to allow for their continued safe operation.

Some LILW contain long-lived radionuclides that require more isolation from the biosphere than short-lived wastes. Disposal for these types of wastes will typically be provided in geologic formations of several hundred meters of depth, along with high level wastes. As of now this type of wastes remain in temporary storage pending final disposal (See *Deep Geologic Disposal*, this Chapter).

HIGH LEVEL WASTE MANAGEMENT

High level wastes amount to less than 10 percent of the total waste produced in nuclear reactors in volume, but this 10 percent accounts for 95 percent of the radioactivity of all the wastes.

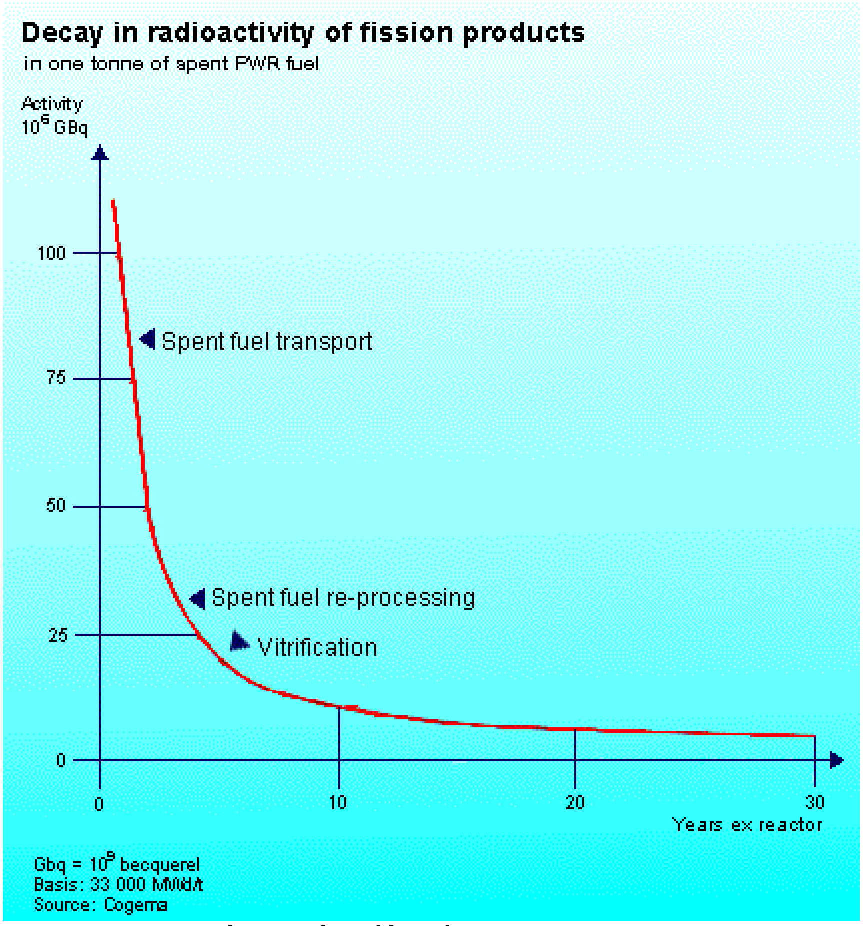
[219] Sutherland (2003).

[220] Grimston & Beck (2002).

There are two different methods to manage spent fuel from nuclear reactors: to dispose of it directly or to dismantle and reprocess it using a chemical procedure to recover unused uranium and plutonium. In both cases at the end it is necessary to dispose of the radioactive material in safe repositories that will ensure its integrity and prevent it from moving for periods in the order of thousands of years.

Whichever method is used, spent fuel must first undergo a cooling and decaying period of 30 to 50 years. In the 40 years immediately following its removal from the reactor, the level of heat and radioactivity from the spent fuel falls to about one thousandth of its original level, which makes this a required step to minimise the costs of handling fuel heat and radioactivity either for disposal or for reprocessing. One of the methods used to do this is interim dry storage. Spent fuel is stored in containers made of materials such as steel, steel reinforced concrete and lead, filled with inert gas, and placed above ground on concrete pads or in concrete bunkers on-site (on nuclear plant grounds) or in other dedicated sites.

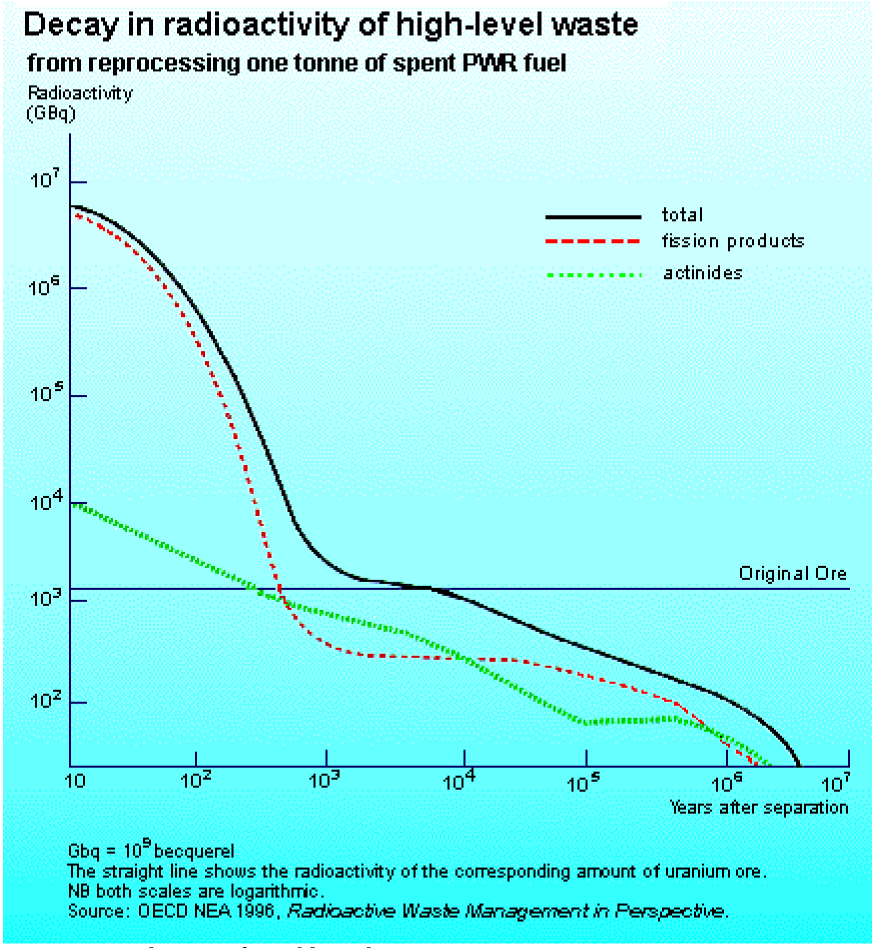
Figure 41 Radioactivity decay of fission products



Source: COGEMA by way of World Nuclear Association.

Conditioning of spent fuel for final direct disposal involves packaging the complete fuel assemblies in purpose built sealed stainless steel containers for its placement in final repositories. Nuclear fuel is already in very stable ceramic form that securely locks the radioactive products contained within. Fuel in some instances can be subject to a volume compaction process before packaging that involves removal of the metallic structural components and piling of the resulting fuel pins in a more compact array. These are then sealed inside stainless steel containers for final disposal. United States, Canada and Sweden have opted for direct disposal of spent fuel, although in the case of Sweden it will allow for future retrievability if required.

Figure 42 Radioactivity decay of fission products and actinides after cooling down period and reprocessing



Source: NEA by way of World Nuclear Association.

In reprocessing, spent fuel is stripped of its structural components and dissolved in a chemical procedure using nitric acid in which uranium and plutonium are separated for further use. Around 1 percent (of the original 5 percent) of uranium-235 and 1 percent of newly produced plutonium are present and recoverable from spent fuel after removal from a nuclear reactor, and when recycled can save approximately 30 percent of the uranium required to produce a new fuel element. Spent fuel contains fission products such as various isotopes of barium, strontium, caesium, iodine, krypton and xenon; and actinide elements such as americium, neptunium and curium. Fission products are the fragments of fissioned uranium atoms and have the highest levels of radioactivity and the shorter half-lives in the high level waste. Actinides (elements with atomic number higher than element 89 – actinium) are produced by neutron capture of uranium and have less relative radioactivity than fission products but carry longer half-lives in the order of a thousand years or more. The diagram in Figure 41 shows how the collective radioactivity of fission products decays to one percent of its original level a couple of decades after being removed from the reactor, and to less than 0.1 percent after 40 to 50 years. Figure 42 shows how after the original cooling down period and separation of uranium and plutonium, it takes between a few hundred years to a few thousand years for fission products and actinides together to further decay to levels below that of uranium found in mines.

When fuel is reprocessed, only about 3 percent of the original volume ends up as highly radioactive waste. Reprocessing therefore has the added advantage of minimising the volume of high level waste that has to be finally disposed of. After removal of the uranium and plutonium, the resulting highly radioactive fission products and actinides in liquid form are first stored temporarily for further cooling, and are later immobilised in a stable and insoluble form usually by vitrification into a matrix of borosilicate glass inside stainless steel flasks or canisters. In this form the wastes are ready for final disposal. Reprocessing has been fully deployed industrially and commercially. France, Japan, Russia, and the United Kingdom have commercial reprocessing facilities currently in operation. Belgium, Germany, and Switzerland have reprocessing programmes and obtain those services from other economies. China is also committed to reprocessing and has a commercial facility planned for the future.

FINAL DISPOSAL OF HIGH LEVEL WASTES

To date no facility has been implemented for the final disposal of civilian high level waste anywhere in the world, but significant advances have been made in the development of the technology to the point that deep geological disposal, the most favoured method, is now considered mature enough for deployment. One facility of this type has been constructed and is in operation in New Mexico, United States, since 1999 for the final disposal of long-lived transuranic[221] wastes derived from the United Sates military nuclear programme.

The reasons there are no facilities to store civilian high level wastes today are many: delays due to regulatory issues, legal controversy, staunch public opposition, and difficulties encountered in the development of the technology. But there are also two important factors to consider: one is that the cost of a deep geologic facility is enormous independent of scale, and the organisations or people responsible to make the investment will be reluctant to do so until it can be justified by the production of a sufficient amount of HLW or spent fuel.

The second is that there is no technical or logistical need to have final disposal for high level wastes at this point in time. Most of the fuel in existence in the world today is undergoing the pre-required 30 to50 year cooling down period in interim storage. The lack of repositories has become a problem only for earlier nuclear plants in some places in the world that are beginning to run out of storage capacity that was not originally intended to hold fuel for so long. In many of those cases the problem has been solved by adding above ground, interim dry storage capacity on site.

For the final disposal of high level wastes, many options have been evaluated over the years: ocean floor and under-seabed disposal, ice-sheet disposal, space disposal, supervised storage, transmutation, and deep geologic disposal. Disposal on or under the ocean seabed and in the polar ice-sheet is prohibited by international agreements[222]; launching waste into orbit around the sun or directly into the sun is resource-intensive and presents major risk of accidents during launch; supervised storage is not in good favour because it shifts responsibility to future generations; and transmutation, in which radioactive materials are *transmuted* into other less dangerous elements through bombardment in particle accelerators, is at an early stage of development and still requires the disposal of the remaining waste (see *Transmutation and Accelerator Driven Systems*, this Chapter).

DEEP GEOLOGIC DISPOSAL

Deep geological disposal is the only scientifically and technically credible long-term solution to meet the need for safety without reliance on active supervision. Most nations where long-lived radioactive waste is an issue ultimately aim for geologic disposal. Deep underground repositories provide security and long-term integrity of the waste over geologic time scales. There are many locations on earth where rock structures have been stable for more than half of the Earth's 4.5 billion years; it is therefore safe to assume that radioactive waste material placed in such places will remain intact and with no significant movement after isolation periods of 1,000 years or more.

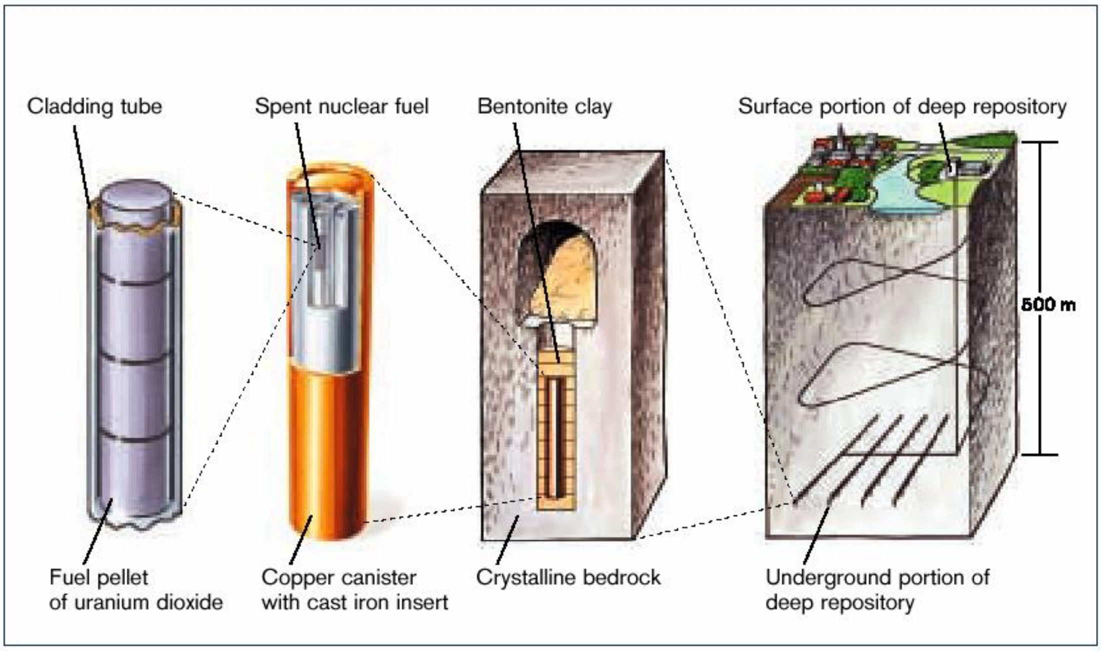
An important tool in the development of deep disposal technology has been the study of *analogues*, or naturally occurring reactors discovered in some uranium deposits in the earth's crust. These natural reactors formed almost 2 billion years ago and are important for the assessment of geologic repositories as they provide valuable information on the containment and migration of highly

[221] Plutonium and other actinides with an atomic number above 92 (uranium).

[222] The London Convention of 1993 prohibits disposing of radioactive materials at sea until 2018; the Antarctic Treaty of 1959 prohibits disposing of radioactive waste in the Antarctic continent.

radioactive materials for geologically long periods of time. The most significant case occurred at Oklo in what is now Gabon in Africa, where at least 6 spontaneous nuclear reactors formed inside a rich vein of uranium ore and continued reacting for about 500,000 years, generating all the radionuclides found in HLW including more than 5 tonnes of fission products and 1.5 tonnes of plutonium, all of which remained at the site and decayed into non-radioactive elements.[223] The reactors materialised due to the presence of groundwater in the uranium deposits at a time on earth when uranium U-235 had concentrations similar to those required inside a modern reactor (water and a U-235 concentration of about 3 percent are required for a nuclear chain reaction).

Figure 43 Deep geologic disposal



Multiple barriers prevent the radionuclides from reaching the ground surface.

Source: Guais (2003).

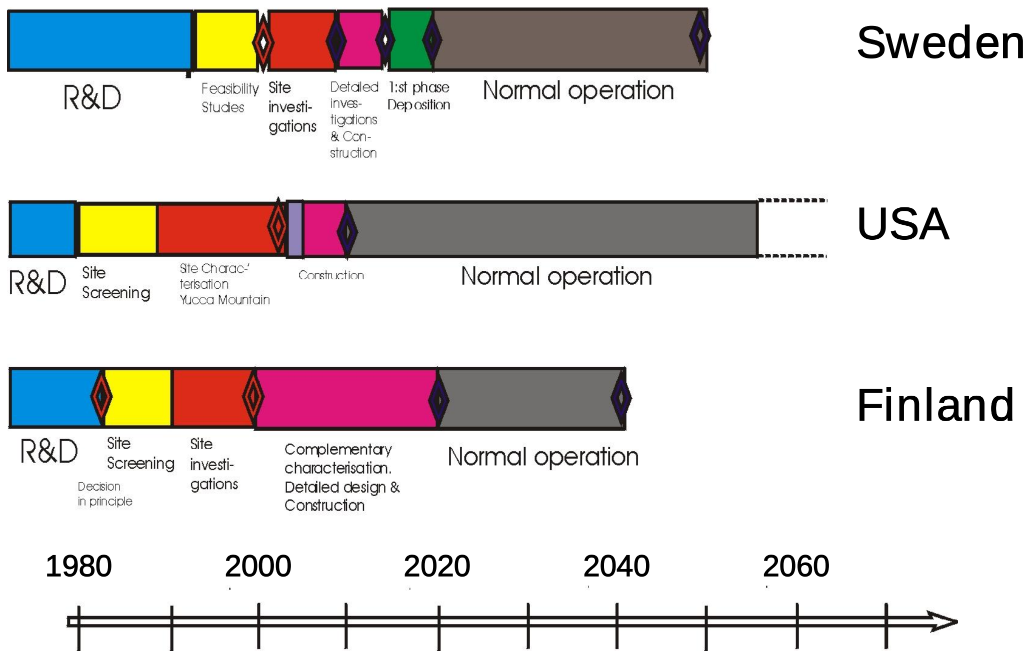
In deep geologic disposal, underground repositories are constructed in stable rock structures about 500 metres deep or more. In most approaches, conventional mining techniques will be used to construct long connecting shafts and rooms inside the rock formation. Corrosion resistant stainless steel waste canisters containing complete fuel elements or HLW from reprocessing will be placed in suitably-spaced holes in the floor at several levels. Incorporated into the construction will be the concept of *engineered safety barrier design*, which is the integration of engineered barriers into the natural features of the site to further ensure the long-term integrity of the guarded material. Three types of geological structures are being studied for the purpose of deep underground storage: hard crystalline rocks, argillaceous rocks (clays) and rock salt beds.

In the last 10 years of deep geologic disposal development, there has been significant progress in the scientific understanding of the related phenomena, experience has been acquired in the laboratory and in the field including the study of analogues, site characterisation, and safety assessment techniques. Today it is assumed that the technology is mature enough for deployment, even if scientific work remains ahead in the interface between natural and man-made components, and in adapting technologies and methods to specific sites.

223 WNA (2004d).

Currently 16 members of the Nuclear Energy Agency of the OECD have active programmes for geologic disposal.[224] Suitable locations have been defined in several economies and sites are now undergoing detailed evaluation. Finland and Sweden are well advanced in both planning and site selection. Parliaments in both countries decided to proceed on the basis that existing technology is sufficiently advanced and safe. In the United States a final repository site has been selected in Yucca Mountain in Nevada. This will probably be the first commercial site worldwide, to be commissioned some time in the year 2012.

Figure 44 Time schedules of the most advanced economies in the commissioning of a deep geological repository



Source: NEA (2003).

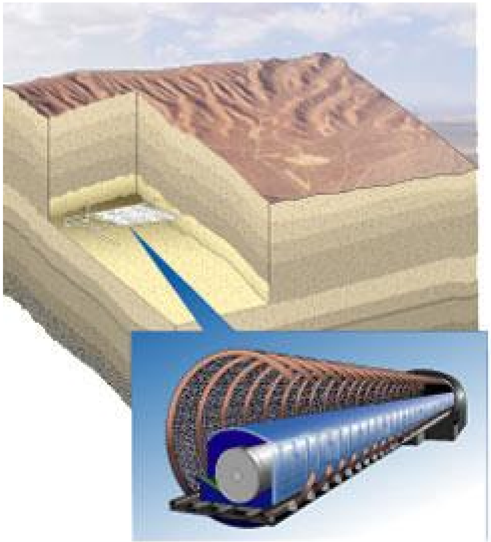
Cost estimates for the development and construction of final disposal facilities have been cited by Sweden, France and the U.K. as being of less than US$ 2 Billion (1999 US$), while the United States and Australia have placed the cost at over US$ 6 Billion.[225] The variations in cost are mainly due to differences in regulatory requirements, specific site characteristics and depth of the underground disposal facility.

One purpose-built deep geological repository is now operating in New Mexico, in the United States for long-lived military wastes. The facility is known as the Waste Isolation Pilot Plant (WIPP), and is the world's first and only underground repository licensed to permanently dispose of transuranic waste. The facility started operating in March 1999 after 20 years of planning and legal and regulatory disputes. It accepts only defence generated transuranic wastes and is not authorised by law to accept spent nuclear fuel or HLW from commercial reactors.

224 NEA (2003).

225 IEA (2001b).

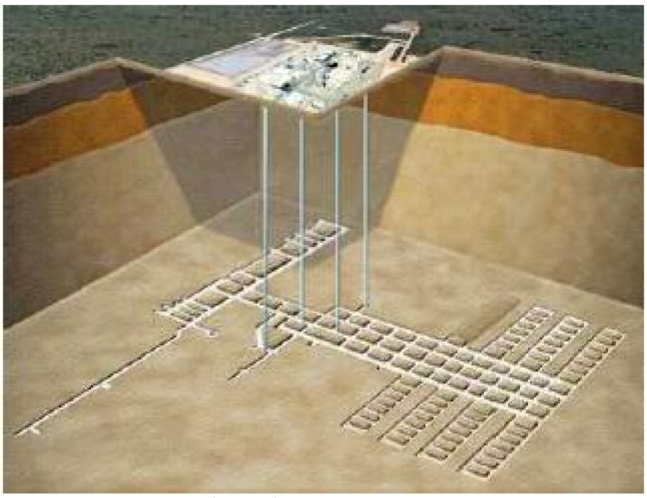
Figure 45 Yucca Mountain repository concept, showing the tunnel layout design and engineered barriers



Source: Yucca Mountain home page: www.ocrwm.doe.gov

The site is located in the Chihuahua Desert in Southeastern New Mexico and the facilities include disposal rooms mined 655 meters underground in a 600 meter thick salt formation that has been stable for more than 200 million years. According to the manager of the DOE site office, WIPP has demonstrated for five years to the United States and to the world that radioactive wastes can be transported and disposed of safely, protecting people and the environment. After 5 years of operation, the repository has received 2,400 waste shipments and holds more than 19,000 cubic meters of radioactive wastes. It receives around 20 shipments of waste every week from different locations around the United States. The facility is projected to have 8 disposal rooms, or panels, each one the size of a football field. Panel 1 was filled and has been closed since July 2003. Panel 2 is being used for disposal now and mining for Panel 3 is almost complete.[226]

Figure 46 Diagram of the Waste Isolation Pilot Plant in New Mexico, United States



Source: USDOE (2004c).

[226] USDOE (2004c).

TRANSMUTATION AND ACCELERATOR DRIVEN SYSTEMS

An alternative strategy for the management of HLW, but one that is at an early stage of development, is partitioning and transmutation. The process is being studied for future application as a way to significantly reduce the radiotoxicity of waste decreasing both the volume of high level waste and the time needed for it to decay to harmless levels, allowing for it to be stored in smaller and less sophisticated underground repositories.

The process separates long-lived actinides (partitioning), particularly neptunium, americium and curium, and converts them into shorter-lived radionuclides (transmutation) such as fission products. Transmutation is performed in a high-energy particle accelerator, where a beam of high-energy neutrons acting on a target such as tungsten, tantalum, depleted uranium, thorium, zirconium, lead, or mercury, produces neutrons (spallation) that then generate fission reactions similar to the ones inside a nuclear reactor, although at lower energy levels and in lower numbers. The reactions break heavy actinide elements into fission products. By recycling the process many times over, the toxicity of high level waste can be reduced to the point where it can decay to levels below those of uranium ore after periods of less than 1,000 years.

The phenomenon of spallation is also used in a type of nuclear reactor currently under study called Accelerator Driven System. In this type of reactor a fraction of the neutrons required for fission reactions are not provided by a self-sustaining uranium or thorium chain reaction, but by the spallation phenomenon using a particle accelerator. Uranium or other nuclear fuel is placed surrounding the target material so that the neutrons produced by spallation go on to produce more fission neutrons and more fission reactions for the production of power and for the transmutation of actinides. Such a reactor would be safe to operate as it could be turned off by simply shutting down the accelerator neutron beam, avoiding the need to introduce control rods to absorb neutrons for a delayed shutdown, as in a more conventional nuclear reactor. This type of reactor is being studied and developed in India using thorium as nuclear fuel.

Because of the possibilities of this technological option in the future, economies such as Sweden are opting for final disposal systems for high level radioactive wastes that have retrievability built-in. This would allow extracting and processing the waste material at a moment in the future when this or other processing technology becomes mature and economical.

INTERNATIONAL REPOSITORIES

An idea that has been given active consideration for some time is that of multi-nationally shared waste repositories. From an ethical, and in some cases legal standpoint, nuclear wastes are better disposed of by each individual economy that produces them.[227] However, the idea seems to have merit and thus some suggest it deserves further analysis and an effort to find ways to handle the legal limitations.

The most obvious advantage of such a facility is economics. The unit cost of a repository is not directly proportional to its volume as several of the costs are more or less fixed, such as the supporting scientific research, site selection and characterisation, preparation of the safety enclosure, public inquiries, construction of a surface waste reception area, and final closure and decommissioning. A deep geological facility would be likely to cost over US$ 1 billion, no matter how small the volume of wastes to be disposed of; and can go as high as US$ 2 to 6 Billion as mentioned earlier. A single large facility scaled to receive the HLW from a number of countries would therefore prove more economically efficient.

To economies hosting the operation of a facility like this, it could represent a considerable source of income measured in the tens of billions of dollars. On the other hand, there are economies with nuclear plants that do not have suitable geology for a disposal site. As well, economies with small

[227] The Basel Convention of 1989 prohibits the export of hazardous wastes from Parties that are members of the European Union, the OECD and Liechstenstein, to all other Parties to the Convention.

nuclear programmes, or economies that are considering to incursion into nuclear power at a small scale might find it too burdensome technically or economically to embark on a geologic repository and could be potential customers. Also, some economies might conceivably welcome the opportunity to rid themselves of the task of handling and establishing safeguards and controls for the plutonium existing in spent fuel.

In Russia, a law was passed in 2001 that made the import of spent nuclear fuel from abroad possible for reprocessing or storage. Since the law was passed, Russia has imported spent fuel from Soviet-built nuclear plants in Bulgaria and Ukraine. Even though the activity stopped for a while, it was later announced that imports were to be resumed by the end of 2003. Russian officials have said that this activity could earn Russia US$ 20 billion over the next decade.

In another instance, an Australian research group in the 1990s identified sites with appropriate characteristics for deep geologic repositories where geology had been stable for several hundred million years in Australia, southern Africa, Argentina and western China, and favoured Australia on economic and political grounds. The proposal met with poor enthusiasm and prompted the federal government of Australia to reiterate its long-standing and bipartisan policy of not importing nuclear wastes and to announce that there was no immediate intention of considering such proposal. Nevertheless, the proposal was originated on previous initiatives within the government of Australia to analyse the possibility of offering nuclear fuel cycle services internationally, including uranium enrichment and management of nuclear wastes.

Overall, little progress has been made to date in partnership agreements for a joint waste disposal project. There has been much public criticism over the concept and a divergence of views among potential partners concerning mainly timing issues and practical feasibility. To be successful, international initiatives should accommodate the differences in concept and timing of each economy's waste management programmes, and should be sensitive enough to place the proper consideration to issues important to each. The end product should be careful not to be obstructive to each nation's programmes.

The way international law stands today, it would be difficult to establish a network of international radioactive waste disposal centres. Neither political opinion nor international law favour the movement of hazardous materials between nations, but have been moving toward accepting it in those cases where the nation originating the materials is technically or financially incapable of disposing of them safely.[228]

But even this way of thinking is susceptible to change. In a more recent case, Italy announced in 2004 that it is hoping to export 99 percent of its nuclear waste to the United Kingdom after public demonstrations made it impossible to find a suitable site on Italian soil. A decree allowing the export of waste was signed at the end of 2004 and it will become law in Italy sometime in 2005. Italy has 235 tonnes of spent fuel remaining from the decommissioning of its reactors after the accident at Chernobyl. In the UK the Department of Trade and Industry relaxed existing rules that required the waste to be returned to the country of origin. The British government has said that retaining waste from half a dozen customers of BNFL would increase the revenue of the state-owned company by 689 Million Pounds per year. The Italian government is now negotiating with British Nuclear Fuels Limited the reprocessing of the fuel, provided the United Kingdom retains the waste and the recovered uranium and plutonium.[229]

The International Atomic Energy Agency supports consideration of a multi-national approach to the management and disposal of spent fuel and radioactive waste. It emphasises the fact that not all countries have appropriate geological conditions for disposal and that the cost in financial and human resources for a geological disposal facility could be unbearable for countries with small nuclear programmes. The IAEA has also indicated that advantages in cost, safety, security and non-proliferation would be gained from international cooperation in this area. A report from the IAEA in 1980 recommended the elaboration of proposals for establishing multinational and international

[228] Grimston & Beck (2002).

[229] The Guardian (2005).

repositories, stressing that centralised facilities for disposal of spent fuel and HLW would reduce the risk of nuclear material proliferation, and be more economical.

AREAS FOR COLLABORATION IN APEC

There are different areas for possible collaboration in APEC economies regarding waste disposal technology, both in the high level and in the low and intermediate level categories.

One possibility that can be considered for the future, even with the difficulties noted in the previous section, is the establishment of one or more regional waste repositories for final disposal of HLW. Advantages of such collaboration can be envisaged for specific areas of APEC. The Northeast Asia area is home to five neighbouring economies with substantial nuclear programmes that could obviously benefit from sharing the construction and operation expenses of a deep geological repository. A similar case is that of Canada, United States and Mexico in North America. Mexico with only two reactors in operation at present could especially benefit from such an arrangement.

In Southeast Asia there is the possibility of Vietnam and eventually other nations of adopting nuclear programmes, although at a smaller scale than those of China, Japan, Korea, or Russia. That would make the former economies also prime candidates for joining an international repository scheme with the latter.

But closer to the present there are other collaboration possibilities open. The whole burden of undergoing a development programme to develop the scientific research for deep geologic repositories makes it difficult for many economies to tackle by themselves. Collaboration agreements could be established to share the financing of research and resource-building projects. One such project could be organised for the joint construction of research and test underground waste facilities. Underground research laboratories (URLs) are essential to provide the scientific and technical information and the practical experience needed for the design and construction of radioactive waste disposal facilities, as well as for the development of safety assessment reports that are required at various stages of repository development.

Canada and Belgium, who own such underground research facilities, and in consideration of the expense in time and financial resources needed for their construction, have offered them to the IAEA to be used as international demonstration and training centres. The IAEA has since established a research network to provide assistance to other economies in the early phases of programme development such as site characterisation, defining site selection criteria and overall performance assessment.

Table 41 Examples of underground research laboratories

Economy	Laboratory	Host rock	Organisation
Canada	URL Manitoba	Granite	AECL, since 1984
Japan	Tono	Sediment	JNC, since 1986
Sweden	Äspö	Granite	SKB, started 1990
Switzerland	Grimsel	Granite	NAGRA, since 1983
	Mont. Terri	Opalinus clay	SHGN, initiated 1995
France	Tournemire	Sediments	ANDRA, IPSN, since 1990
Belgium	URF Mol/Dessel	Boom clay	SCK/CEN, since 1984/1999
USA	ESF Yucca Mountain	Welded tuff	USDOE, since 1996/1998

Source: NEA (2003).

APEC economies can also benefit from collaboration in LILW waste activities. Particularly, the problem of handling low and intermediate level wastes arising from nuclear plants and from medical and industrial applications is more immediate than the final disposal of HLW and there are a number of topics in LILW where technology can be transferred to less advanced economies. Topics could include: design and operation of LILW surface storage installations, waste processing and preparation methods, monitoring systems, sealed radioactive sources disposal concepts, licensing standards and procedures, among others.

Other technical cooperation activities could be directed at capacity building, development of a legislative framework and safety culture in waste management, waste transportation regulation, and the addressing of specific technical issues related to waste management facilities and disposal. Mechanisms for collaboration could include expert services, fellowships for staff training, technology transfer and provision of equipment.

CONCLUSION

Of the two types of radioactive wastes produced by the civilian nuclear industry, LILW is the one for which management technology has been advanced the most with much experience gained to date and many facilities already in operation worldwide.

For HLW on the other hand, even though experience exists in all aspects of its handling that allow for it to be carried out safely, including spent fuel conditioning, reprocessing, immobilisation, transport and interim disposal, there exists no civilian final repository in operation as of yet.

However, the technology is considered to be in a mature state of development for the case of deep geologic disposal, which is considered by many economies with nuclear plants as the best option for the final disposal of high level wastes. And even though there is no urgent need at present for a civilian final HLW repository today given that most fuel in the world is currently undergoing the decaying and cooling-off interim storage period, plans are well underway in a number of economies for the implementation of deep geologic disposal facilities, with those of Finland, Sweden, and the United States being the most advanced. Expected operation of facilities in these last economies is slated for sometime after the year 2010.

The Waste Isolation Pilot Plant (WIPP) deep geological repository has been operating in New Mexico since 1999 for the final disposal of military long-lived transuranic elements generated by the nuclear weapons programme of the United States, and is proof that the technology for the safe disposal of long-lived radioactive wastes is mature and can be implemented successfully.

There are a number of possibilities for collaboration among APEC member economies in different areas of waste management. The establishment of multi-national, regional final disposal repositories for high level waste can prove to be economically efficient and safe, and can help solve the challenge of disposing of HLW for economies with small nuclear programmes or without the appropriate geological characteristics. However their implementation requires coordinating the requirements and timing of waste management programmes among several nations and circumventing existing legal limitations.

More accessible and fruitful in the short term could be collaboration in HLW and LILW in the areas of: capacity building, joint research, development of regulatory framework and joint construction and operation of underground research laboratories.

SECTION 3

FUTURES

CHAPTER 6

ALTERNATIVE NUCLEAR POWER FUTURES IN APEC

INTRODUCTION

The present status of nuclear power in the APEC region was described in some detail in Chapter 1: *Nuclear Power Policies in the APEC Region*. We turn the attention now to try to foresee the most probable path this energy source will take in the region in the first half of the 21st century.

In this Chapter we try to assess in realistic terms what the most likely role will be for nuclear power in the energy systems of the next 50 years based on our knowledge of local conditions in the present and expected for the future. With what we know today regarding existing and emerging policies in APEC economies and the expected advances in the nuclear industry, it is possible to make a credible prediction of how much share can realistically be captured by nuclear energy in the power generation systems of the future in APEC.

Nuclear development will also have implications on several aspects of the region's energy systems, and in this chapter we will also try to assess some of them. Increased use of nuclear power would reduce fossil fuel consumption in power generation and therefore it would have effects on the region's dependence on traditional fuels and on the amount of greenhouse emissions produced by the combustion of those fuels. In this chapter we will determine how much conventional fuel can be displaced, its effect on CO_2 emissions, and in energy dependence and security.

Nuclear power can have other far-reaching effects, as well. Extensive use of nuclear power would substantially reduce fossil fuel consumption and would have a decreasing effect on their cost. And because it reduces greenhouse gas emissions, it would also tend to reduce the cost of mechanisms to limit global warming. However, the analysis of these effects is beyond the scope of this study. The determination of the magnitude of conventional fuel displacement and of its related avoided emissions assessed here can nevertheless give a sense of how these variables will be affected in the future.

Three different scenarios are analysed here. A Low Nuclear Development Scenario, a High Nuclear Development Scenario, and a Moderate Nuclear Development Scenario. The low development scenario in a way represents a continuation in the region of the current trends of nuclear energy of expansion limited to a few economies and no much enthusiasm for further development in the rest of APEC. The high development scenario on the other end, embodies every economy's most optimistic nuclear development plans and includes nuclear development in some other currently non-nuclear economies as well, assuming nuclear energy gains the favour of power planners region-wide on account of it becoming more cost effective and delivering on its promise of improved safety. The third scenario is a moderate nuclear development case placed somewhere in the middle of both extremes.

As will be seen from the defining conditions for each scenario, all three of them are built upon realistic conditions and they all have a real probability of happening. Which path is taken will depend on how each of the issues having influence on the future of nuclear energy evolves in the following years.

The details of each scenario are described in the following sections.

NUCLEAR SCENARIO SETTINGS

Projections for the different scenarios were developed over a 50-year period, covering the years 2000 to 2050. Baseline conditions for all the nuclear development scenarios assume an average annual economic growth rate in terms of GDP for the whole of APEC of 3.0 percent between the years 2000 and 2050 (based on real GDP in 1990 $US). This growth results from a GDP average annual growth rate for developing economies within APEC of 5.1 percent and an average annual growth rate for industrialised economies of 2.5 percent in the same period.

The baseline assumption for electricity demand is an average annual growth rate for the whole of APEC of 2.8 percent, similarly divided between developing economies at 4.3 percent, and industrialised economies at 1.9 percent within the 50-year study period.

In both GDP and electricity demand, rather than opting for different growth rates that would cover a range of possibilities, only one rate of growth was selected for simplicity that is considered to be a fair representation of a middle ground, or moderate rate of growth development for the region.

The projections calculations for the three scenarios were made on an economy by economy basis, with determinations made of electricity demand, contribution of different fuel sources and nuclear capacity growth possibilities for each of the 21 APEC economies, even if the results shown here do not mention all of them by name.

The evolution trends for all the different power generation fuels during the study period (aside from nuclear power itself) were determined based on the general assumptions made in the latest APERC Outlook 2002, with corrections added to account for specific circumstances expected of this 50-year period, such as improved development of renewable technologies or predicted rates of depletion for certain fuels.

As mentioned before, three different nuclear expansion scenarios are constructed over this basic setting, the details of which are defined in their respective sections.

Fifty years is used as an average lifetime for nuclear power plants, a reasonable average considering that plants usually are designed for a 40-year lifetime and that some units apply for 20-year life extensions. An average plant capacity factor of 85 percent for nuclear plants is considered in all cases.

LOW NUCLEAR DEVELOPMENT SCENARIO

A first scenario is drawn out to represent the low end of nuclear development in APEC, characterised in part by conditions of preservation of the status quo in the industry. The scenario is representative of the situation prevalent today in which only a few economies in the Asian region of APEC are committed to nuclear power and have firm plans for new plants; but at the same time there is no clear commitment from utilities in other industrialised and developing economies alike to become involved in a nuclear resurgence. We call this the Low Nuclear Development Scenario and use it as a basis for comparisons with the other two scenarios.

The scenario is built upon the supposition that the nuclear industry will not enjoy the best of conditions in the next 50-year period. This would be the case for instance if the nuclear industry does not deliver on its promise to significantly reduce capital costs for new units, or if the cost of new models of nuclear plants does not come down after the construction of the first few units as expected, or if construction periods continue to be difficult to control. Other conditions that would contribute to a difficult environment for nuclear power would be that the prices of alternative fuels for power generation do not increase substantially as expected; that no facility for the final disposal of nuclear waste is put into operation, creating doubt among policymakers and the public in general as to whether this issue can be resolved at all; and a continuing opposition to nuclear power in many economies resulting from all of the above.

Table 42 Specific considerations for nuclear development in APEC economies in the Low Nuclear Development Scenario

Canada	No new constructions. Retirements start in the year 2021 (based on the age of existing nuclear plants). Last nuclear plant retired in 2043.
China	Slower than officially projected economic growth considered, together with non-optimum conditions for nuclear power, limiting nuclear expansion to 5-8 GW (5-8 nuclear plants) per decade. Present capacity: 7 GW Capacity under construction available by 2010: 6 GW.
Chinese Taipei	2.7 GW under construction available by 2006-7. No new constructions after that. Retirements start in the year 2027. Capacity still in operation in 2050: 2.7 GW (based on nuclear plant lifetime).
Japan	Policy to replace only a fraction of existing plants (as opposed to replacement of all existing plants) that reach the end of their lifetime. Nuclear capacity in 2004: 47 GW. Capacity approved and available by 2010: 4 GW
Korea	Policy to replace only a fraction of existing plants that reach the end of their lifetime. Nuclear capacity by 2004: 17 GW Capacity under construction and available by 2010: 5 GW.
Mexico	No new constructions. Retirement of two existing plants in 2039 and 2044.
Russia	Non-optimum economic conditions do not allow current expansion plan of nuclear power generation doubling by 2020. Only capacity under construction, approved replacement capacity, and 5 GW additional capacity considered for the 50 year period. Nuclear capacity in 2004: 22 GW. Capacity under construction and available by 2010: 5.5 GW Capacity replacements approved: 6 GW. Retirements begin in 2021.
United States	No new constructions. Uprates worth 3.9 GW are considered by 2010. Retirements start as early as 2010. Last unit retired in 2046.

Under this setting, specific assumptions are that nuclear capacity additions are limited to China, Japan, Korea and Russia, which are already committed to nuclear programmes. The rate of construction in these, however, is limited to less than their announced intentions on account of conditions not being optimal for nuclear power. For the other economies with nuclear plants: Canada, Chinese Taipei, Mexico and United States, it is assumed that no new nuclear additions are made and that current reactors are retired at the end of their useful life (after extensions) with no replacement. It is further considered that no other economy in APEC ventures into nuclear energy. More detail on the specific assumptions for different economies in APEC as used in the projection model is listed in Table 42.

RESULTS

Under the assumed conditions for this scenario, generation from nuclear power in APEC continues its increasing trend in the first part of the 50 year period, going from 1,415 TWh in 2003 to a peak in the year 2013 of 1,865 TWh. After 2013 the number of retirements begin to outnumber new additions causing nuclear generation to start a gradual decline to 1,718 TWh by 2025 and finally to 867 TWh by 2050. Figure 47 graphically shows the evolution of the power generation fuel structure in the 50-year period. The share of nuclear generation in the fuel mix diminishes to 9 percent in the year 2025 and reaches a small value of 2.4 percent in 2050 as can be seen in Table 43.

Figure 47 Power generation fuel structure evolution in APEC in the Low Nuclear Development Scenario, 2000-2050 (TWh)

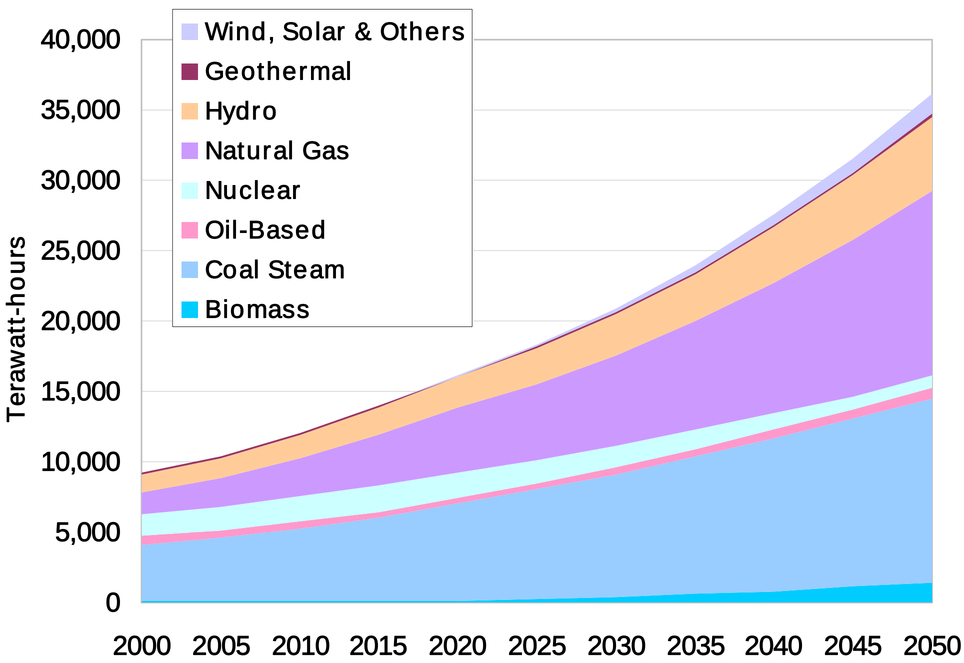
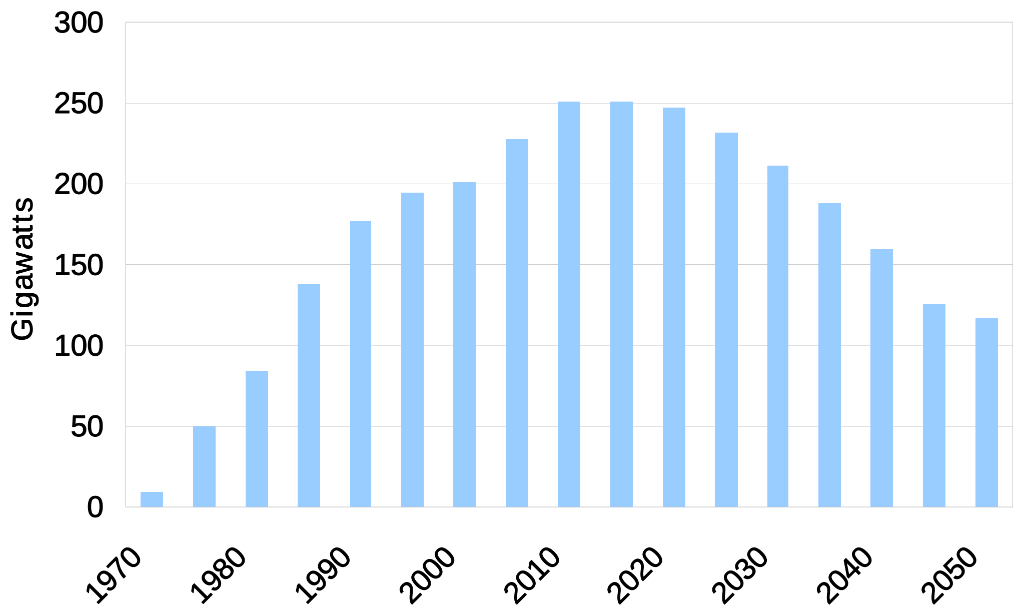


Figure 48 shows the historical nuclear installed capacity in APEC from 1970 to 1999, and the projected capacity from 2000 to 2050 in the low nuclear development scenario. It also shows how the total nuclear installed capacity in APEC peaks in the year 2013 at 251 GW and starts its decline to reach 231 GW in the year 2025 and 117 GW by the year 2050, when only China, Chinese Taipei, Japan, Korea and Russia will still have reactors in operation.

Table 43 Power generation fuel shares in APEC in the Low Nuclear Development Scenario (Percentage)

	2000 (%)	2025 (%)	2050 (%)
Biomass	1.2	1.5	4.0
Coal	44.0	42.1	36.1
Oil	6.6	2.4	2.1
Nuclear	16.2	9.3	2.4
Natural Gas	17.1	29.3	36.3
Hydro	14.3	13.7	14.7
Geothermal	0.5	0.5	0.7
Wind, Solar & Others	0.1	1.1	3.7
Total	100.0	100.0	100.0

Figure 48 Historical and projected installed nuclear capacity in APEC in the Low Nuclear Development Scenario, 1970-2050 (GW)



HIGH NUCLEAR DEVELOPMENT SCENARIO

The high-end nuclear growth scenario is built on the premise that the nuclear industry enjoys favourable conditions all around, and becomes a viable and popular option for electricity generation in many APEC economies. Such a condition would be feasible if the economics of new reactor models meet the targets claimed by manufacturers; if joint-ventures can be formed successfully to share the risks of first plants; if technical concepts for the final burial of nuclear waste can be constructed and proven technically worthy; if the current safety record in reactor operations continues, and if appropriate measures are agreed upon by the international community to allay fears of nuclear proliferation, to name only a few. Other factors that could improve the outlook for nuclear development would be external issues such as an increase or volatility in the prices of fossil fuels; an intensification of carbon emissions control policies like carbon taxes or emissions trading; and a delay in the implementation of other clean technologies like renewable energies.

Under these conditions, we assume that economies with current plans for nuclear power expansion are able to carry out their most ambitious targets, specifically: China, Japan, Korea, and Russia. It is also assumed that nuclear economies with no present plans for expansion decide on adding new nuclear capacity, specifically: Canada, Chinese Taipei, Mexico and United States. And it is further assumed that Vietnam and 5 other economies with no nuclear power at present decide to adopt the technology. The criteria to decide how many of the APEC economies with no present nuclear power will adopt it in the future were based on the discussions of Chapter 2: Drivers of Nuclear Policy in APEC. Only Vietnam is mentioned by name as no other economy in APEC besides Vietnam has stated its intentions of pursuing or evaluating the nuclear option. For the purposes of this exercise suffice it to say that in APEC there are at least 6 economies with no nuclear power at present that will face in the next 50 years conditions similar to those that have driven the construction of nuclear power plants in the region.

Table 44 Specific considerations for nuclear development in APEC economies in the High Nuclear Development Scenario

Canada	Present: 13 GW Nuclear share in generation: 12.5% Capacity expansions: 6 GW proposed by AECL for Ontario by 2020; additional 18 GW proposed by 2050.
China	Present : 7 GW Nuclear share: 2.2% Official plan for additional 30 GW by 2020; continued expansion at 20 GW per decade.
Chinese Taipei	Present: 5 GW Share: 21.5% 2.7 GW under construction available by 2006-7; at least a 20% share of nuclear power maintained after that.
Japan	Present: 47 GW Share around 25-30% Official plan: additional 10 GW by 2010; at least a 30% share of nuclear power maintained after that.
Korea	Present: 17 GW Share: 40% 5 GW under construction available by 2010. Official plans for additional 5.2 GW by 2015. At least a 35% share of nuclear power maintained after that.
Mexico	Present: 1.4 GW Share: 5.2% Following new construction in the US, it is assumed that Mexico starts new constructions starting in 2020, aiming at replacing coal-fired share.

Russia	Present: 22 GW Share: 16.5% Official plans: 5.5 GW under construction and 6 GW of replacements by 2010. 5 GW replacements and 20 GW more by 2030. Similar growth rate maintained after that.
United States	Present: 103 GW Share: 19.9% Start new constructions by 2015. Increase share of nuclear power with a goal to achieve a balance between coal, gas and nuclear sometime around the year 2050.
New nuclear economies	
Vietnam	Vietnam might approve plans for two to four reactors by 2020. Assumption of between 18 and 23% share of nuclear power by 2030 and maintained after that.
5 economies	Assumption that new confidence in nuclear power prompts constructions in other economies after 2020. With shares of between 10 and 20% by 2050.

For China, Japan, Korea and Russia, new additions are assumed to start immediately as a continuation of their current expansion programmes. For the other economies that do not have current construction programmes, it is assumed that new additions begin somewhere around 2015, a reasonable assumption considering the lead times needed for planning, licensing and construction. Details of the specific assumptions for different APEC economies used in modelling this high development scenario are listed in Table 44.

RESULTS

The High nuclear development scenario has nuclear power becoming the third most important source for power generation in APEC behind natural gas and coal, rising from a 16 percent share today to a 19 percent share in the year 2050 as can be seen in Table 46. Electricity generation from nuclear power increases to 3,132 TWh in 2025 and to 6,916 TWh in 2050. The evolution of the power generation fuel structure throughout the period in APEC can be seen in Figure 49.

The expansion of nuclear capacity in the region under the high development scenario is summarised in Table 45 and can be seen in graphic form in Figure 50. Under the present scenario nuclear capacity expansion is robust in the entire region and achieves high percentage shares of the total generation in a number of economies. Russia reaches a nuclear power share in generation of 38 percent in the year 2050 with the construction of 110 GW of new capacity. Korea reaches a 35 percent share in generation while Japan and United States achieve nuclear shares of 30 percent each. In 6 currently non-nuclear economies including Vietnam, a 10 to 20 percent generation share from nuclear power is attained by constructing from 2 to 6 GW (approximately 2 to 6 plants) of nuclear capacity every 10 years.

Oil is assumed to continue being a part of the fuel generation mix throughout the period, although at very small shares. Oil is and will continue to be used for electricity generation in oil producing economies, and it plays an important role in the efforts for rural electrification in many developing nations.

Table 45 Nuclear capacity expansion in APEC economies in the High Nuclear Development Scenario, 2050

	Total GW nuclear	Added GW nuclear	Build rate 2000-2050, plants/decade	% share in generation
Current nuclear economies				
United States	277	173	35	30%
Russia	132	110	22	38%
Mexico	121	120	24	20%
China	113	106	21	8%
Japan	69	22	4	30%
Korea	57	40	8	35%
Canada	21	8	2	17%
Chinese Taipei	19	14	3	20%
New nuclear economies				
Vietnam	28	28	6	20%
5 economies	95	95	2-5	10-20%

Even with such an impressive rate of expansion, the annual average growth rate of nuclear power generation in the whole of APEC between 2000 and 2050 is 3.1 percent, compared to an average yearly growth rate of 4.5 percent experienced in APEC in the 20 years prior to 2000. The rate of capacity additions, however, is much larger by the end of the 50-year period than it ever was in the nuclear industry's highest expansion era in the 1980s. Capacity additions summed over 5 year periods amount to a value of 142 GW by the year 2050 compared to a peak of 54 GW in the middle of the 1980s as can be seen in Figure 51. (Sums over 5 year periods give a better indication of average capacity additions, as year-on-year additions during the 1980s tended to vary considerably).

Figure 49 Power generation fuel structure evolution in APEC in the High Nuclear Development Scenario, 2000-2050 (TWh)

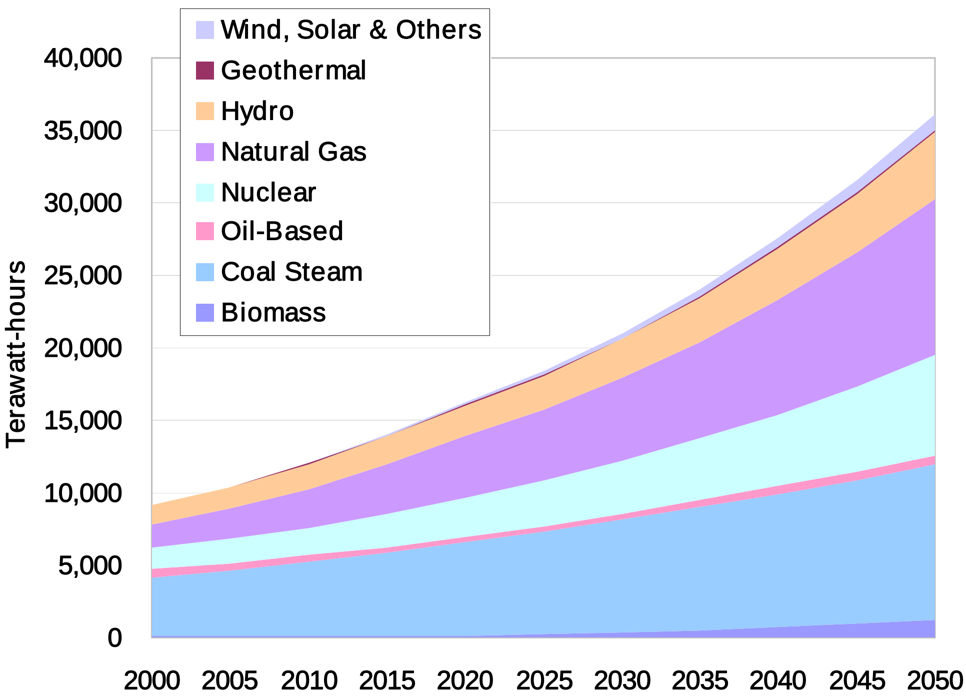


Table 46 Power generation fuel shares in APEC in the High Nuclear Development Scenario (Percentage)

	2000 (%)	2025 (%)	2050 (%)
Biomass	1.2	1.4	3.3
Coal	44.0	38.4	29.6
Oil	6.6	2.2	1.8
Nuclear	16.2	17.0	19.1
Natural Gas	17.1	26.7	30.0
Hydro	14.3	12.7	12.7
Geothermal	0.5	0.5	0.6
Wind, Solar & Others	0.1	1.0	2.9
Total	100.0	100.0	100.0

Figure 50 Historical and projected installed nuclear capacity in APEC in the High Nuclear Development Scenario, 1970-2050 (GW)

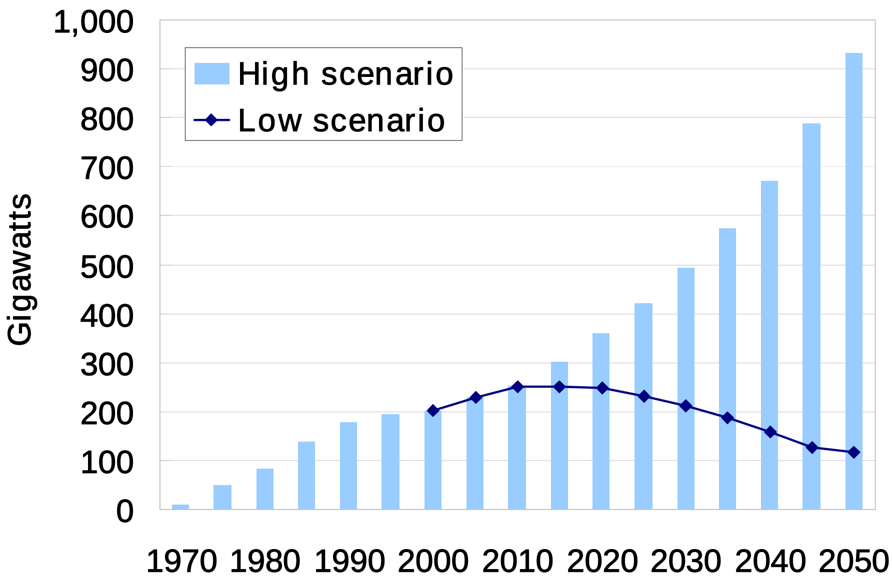
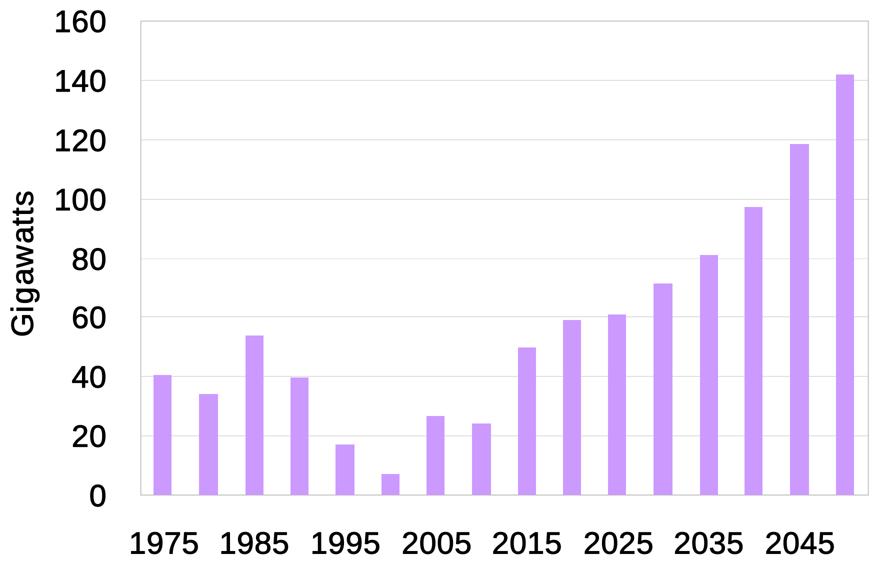


Figure 51 Nuclear power capacity additions summed over 5 year periods in APEC in the High Nuclear Development Scenario, 1975-2050 (GW)



MODERATE NUCLEAR DEVELOPMENT SCENARIO

The moderate nuclear development scenario depicts a middle ground situation for the nuclear industry where some of its most optimistic expectations, but not all, become true contributing to a generally favourable environment for a renewed, if restrained, development. This would reflect a more realistic and probable scenario that could be the result of any combination of factors both for and against nuclear power. For instance: it can result from the realisation that the economics of new power plants are not optimum, delaying by a moderate degree plans for construction in some cases. It can also result from the cost of new reactor models being competitive to alternative plant types; but with licensing and construction time schedules still running longer than optimum. Or from waste disposal facilities being implemented and proven technically feasible; but limited to a few nations because of cost and technical complication. Factors external to the nuclear industry coming together, both for and against, would also contribute to such a middle-ground climate.

Table 47 Specific considerations for nuclear development in APEC economies in the Moderate Nuclear Development Scenario

Canada	Present: 13 GW Share: 12.5% Capacity expansions: 6 GW (8 ACR700s) by 2020 proposed for Ontario by AECL; 15% share of nuclear power maintained from 2010.
China	Present: 7 GW Share: 2.2% Construction rate reduced to one half of that considered in the High development case (10 reactors per decade).

Chinese Taipei	Present: 5 GW Share: 21.5% Share allowed to drop to around 10%.
Japan	Present: 47 GW Share: 25-30% Assumed a policy of replacement of all retired capacity; maintaining nuclear generation constant throughout period.
Korea	Present: 17 GW Share: 40% Assumed policy of replacement of all retired plants, maintaining nuclear generation constant throughout period.
Mexico	Present: 1.4 GW Share: 5.2% Following constructions in the US, Mexico would start constructions starting in 2020, but at a rate smaller than considered in the High development scenario.
Russia	Present: 22 GW Share: 16.5% Assuming financing difficulties in the near future; and beginning of gradual nuclear expansion after 2020.
United States	Present: 103 GW Share: 19.9% Assume replacement of all retired capacity beginning in 2010, plus construction of an additional fraction of plants with goal to maintain a 20% share in nuclear generation.
New nuclear economies	
Vietnam	20% by 2050
2 economies	10% by 2050

In such a case, we assume that China, Japan, Korea and Russia continue with their nuclear expansion plans but tempered to some extent from their most ambitious goals. For Canada, Chinese Taipei, Mexico, and United States, we consider conditions are favourable enough to prompt the drawing of new expansion plans, but at a somewhat lower scale than considered in the high-end case.

For the rest of APEC economies, we reduce the number of nations that venture into nuclear power production to the three economies with the largest expected electricity demand in the future. Vietnam was included again in this group given that in APEC it is the most advanced in terms of feasibility studies for nuclear power, and is also the economy with the highest probability of choosing in favour of new nuclear reactors in the near future, among the APEC non-nuclear community.

As with the high-end scenario, this one assumes that new additions in economies with no current nuclear construction programmes begin somewhere around 2015 to account for the lead times required for planning, licensing and construction. A more detailed economy-by-economy list of considerations used in modelling this scenario is shown in Table 47.

RESULTS

The moderate nuclear development scenario has nuclear generation in absolute terms growing throughout the period, even though its contribution to total power generation diminishes with time. Nuclear generation in APEC increases at a comparatively modest average rate of 2 percent per year over the period in contrast to 3.1 percent for the high-end case, and to 4.5 percent experienced between 1980 and 1999. Nuclear generation goes from 1,415 TWh at present to 2,431 TWh by 2025 and to 3,985 TWh by 2050 as seen in Figure 52. Its share of the total generation, though, diminishes from 16 percent today to 13 percent in 2025 and to 11 percent in 2050, as is shown in Table 49. By 2050, nuclear power is projected under this scenario to be the 4th largest source of electricity generation behind natural gas, coal, and hydro power. As explained before, oil is projected to continue being a part, if somewhat small, of electricity generating systems in oil producing economies and particularly in the electrification of rural areas.

Table 48 shows how generation shares in individual economies achieve lower values than in the high scenario, with the highest being Japan at 23 percent, followed by United States and Vietnam at 20 percent each. Vietnam achieves such a share by constructing an average 6 GW (or approximately 6 plants) per decade.

Figure 53 shows the total installed capacity in APEC every 5 years, as represented by the bars, compared to that of the low-end nuclear scenario, represented by the line. The figure shows graphically how the growth rate in the projected period (2 percent between 2000 and 2050) is lower than that of the historical period between 1980 and 1999 (4.5 percent). (Growth rates for generation are the same as for installed capacity as the relationship between both in the calculation model is assumed to be constant). Total capacity additions in APEC summed over 5 year periods, shown in Figure 54 at the same scale as in Figure 51, can be seen to be reasonably similar to those occurring during the heyday of nuclear construction in the 1980s, reaching 61 GW every 5 years by 2050 as compared to 54 GW per 5-year period in 1985.

Table 48 Nuclear capacity expansion in APEC economies in the Moderate Nuclear Development Scenario, 2050

	Total GW nuclear	Added GW nuclear	Build rate 2000-2050, plants/decade	% share in generation
Current nuclear economies				
United States	184	81	16	20%
Russia	65	43	9	19%
Mexico	61	59	12	10%
Japan	53	6	1	23%
China	52	45	9	4%
Korea	25	8	2	15%
Canada	19	6	1	15%
Chinese Taipei	10	5	1	10%
New nuclear economies				
Vietnam	28	28	6	20%
2 economies	40	40	3-5	10%

Figure 52 Power generation fuel structure evolution in APEC in the Moderate Nuclear Development Scenario, 2000-2050 (TWh)

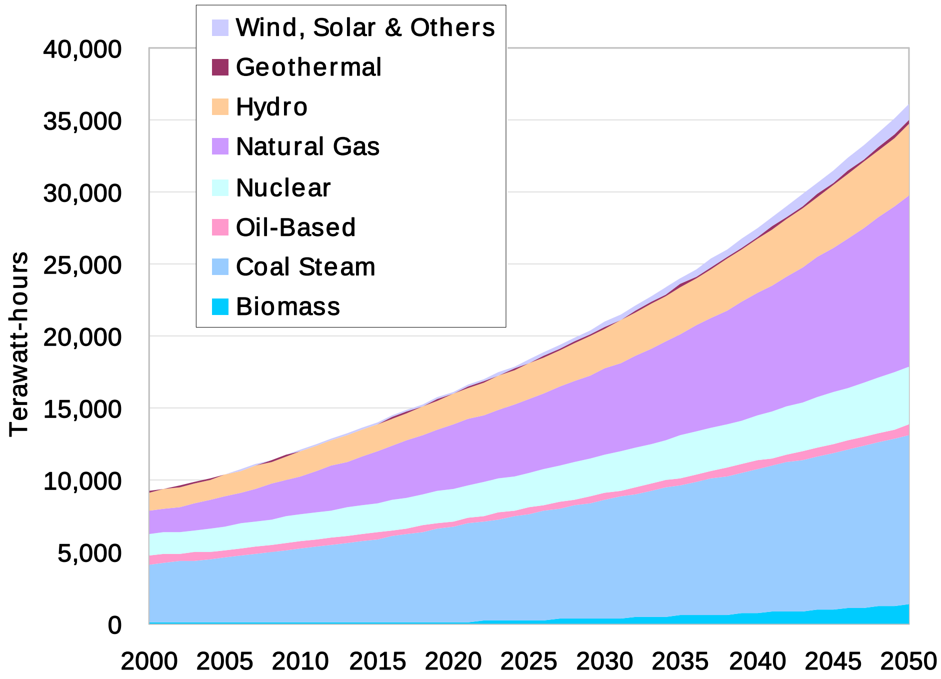


Table 49 Power generation fuel shares in APEC in the Moderate Nuclear Development Scenario (Percentage)

	2000 (%)	2025 (%)	2050 (%)
Biomass	1.2	1.4	3.7
Coal	44.0	40.3	32.7
Oil	6.6	2.3	1.9
Nuclear	16.2	13.2	11.0
Natural Gas	17.1	27.9	33.0
Hydro	14.3	13.2	13.7
Geothermal	0.5	0.5	0.6
Wind, Solar & Others	0.1	1.1	3.2
Total	100.0	100.0	100.0

Figure 53 Historical and projected installed nuclear capacity in APEC in the Moderate Nuclear Development Scenario, 1970-2050 (GW)

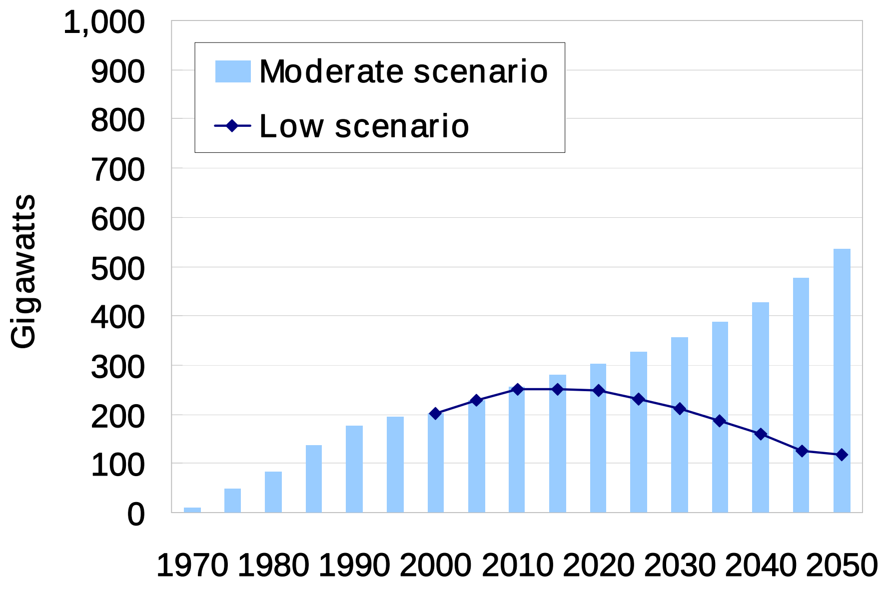
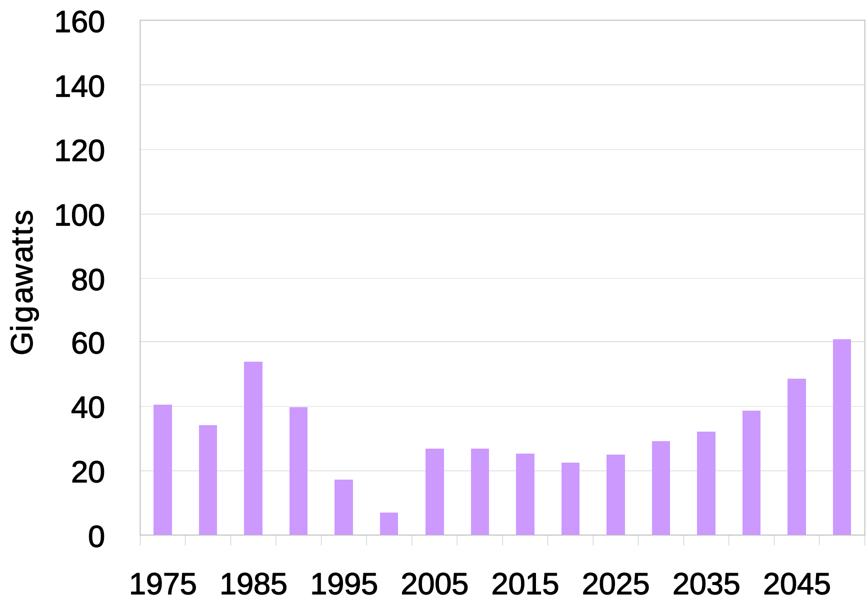


Figure 54 Nuclear power capacity additions summed over 5 year periods in APEC in the Moderate Nuclear Development Scenario, 1975-2000 (GW)



IMPACT ON FUEL USE AND EMISSIONS

FOSSIL FUEL SAVINGS

The most obvious impact that the use of nuclear power brings to electricity generating systems is of course the displacement of other fuels. The type of fuels displaced will depend on the specific characteristics of each economy, but in the APEC region as a whole where most of the electricity generation in the future will be based on coal and natural gas, it is expected that an increase in the use of nuclear power would mainly displace those. Coal generated power is readily interchangeable with nuclear power as both are in essence baseload technologies, and natural gas plants can also conceivably be traded for nuclear power in certain situations where either the price of that fuel is at a premium or the availability is limited.

We analyse here the impact of an expanded use of nuclear power on the amount of fossil fuels used for power generation in both the High and Moderate Nuclear Development Scenarios as compared to the base Low Nuclear Development Scenario.

Figure 55 shows the amounts of coal, oil and natural gas saved in the High and Moderate Nuclear Development Scenarios when compared to the fossil fuels used in the Low Nuclear Development Scenario in all of APEC. By the year 2050, the amount of coal displaced annually in the High nuclear scenario is 540 million toe, while the amount displaced in the Moderate scenario is equal to 282 million toe. Compare that to the total amount of coal used for power generation in APEC in the year 2002: 1,067.4 million toe.[230] As for natural gas, as much as 529 million toe per year can be saved under the conditions assumed for the High nuclear scenario, and as much as 272 million toe per year for the Moderate nuclear scenario, both by the year 2050 and relative to the Low nuclear scenario. Again for comparison, consider that in 2002 all economies in APEC consumed 422.2 million toe of natural gas for power generation.[231]

There are savings in oil too; 27 million toe and 15 million toe annually under the assumptions for the High and Moderate scenarios respectively, relative to the Low scenario. As explained before, it is assumed that oil continues to be used for electricity generation throughout the 50 year study period in oil-producing economies and as an option for rural electrification. For reference, APEC used 158.2 million toe worth of oil in 2002 as fuel for power generation.[232]

Table 50 Fossil fuels displaced annually in the High and Moderate Nuclear Development Scenarios in APEC (Mtoe/yr)

	2025	2035 (Mtoe/yr)	2040	2050
Coal High Scenario	159.2	295.1	373.6	540.2
Coal Moderate Scenario	78.4	151.0	194.2	281.9
Oil High Scenario	6.3	12.9	16.9	26.7
Oil Moderate Scenario	2.7	6.3	8.8	15.0
Gas High Scenario	108.0	232.3	316.5	528.5
Gas Moderate Scenario	57.7	124.1	168.3	272.4

230 EDMC (2004).

231 EDMC (2004).

232 EDMC (2004).

To further appreciate the magnitude of the fuel savings, in the following three figures we compare coal, oil and natural gas inputs for power generation in the whole of APEC between the three scenarios.

Figure 55 Comparison of fossil fuels displaced annually in APEC between the High and Moderate Nuclear Development Scenarios (Mtoe)

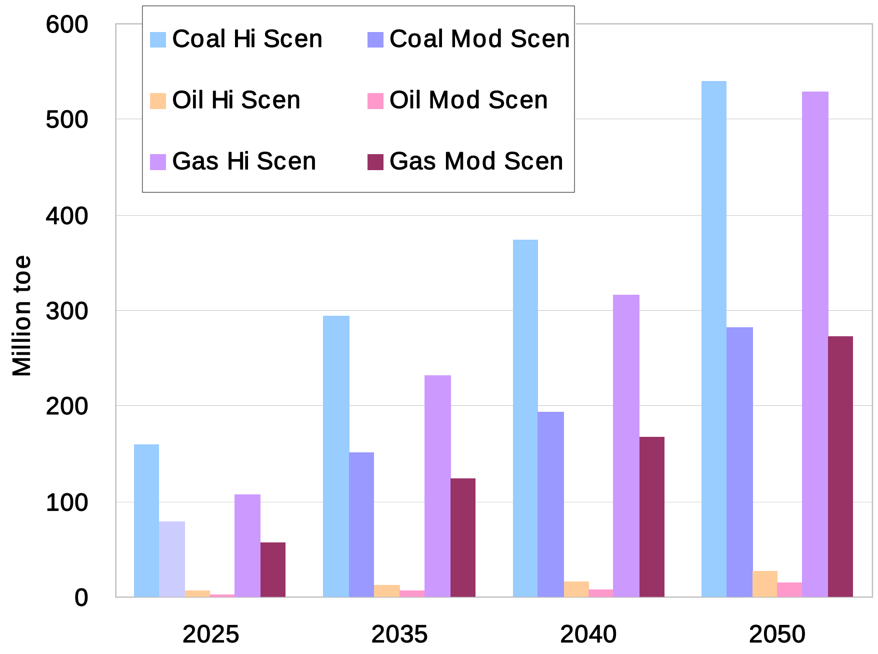
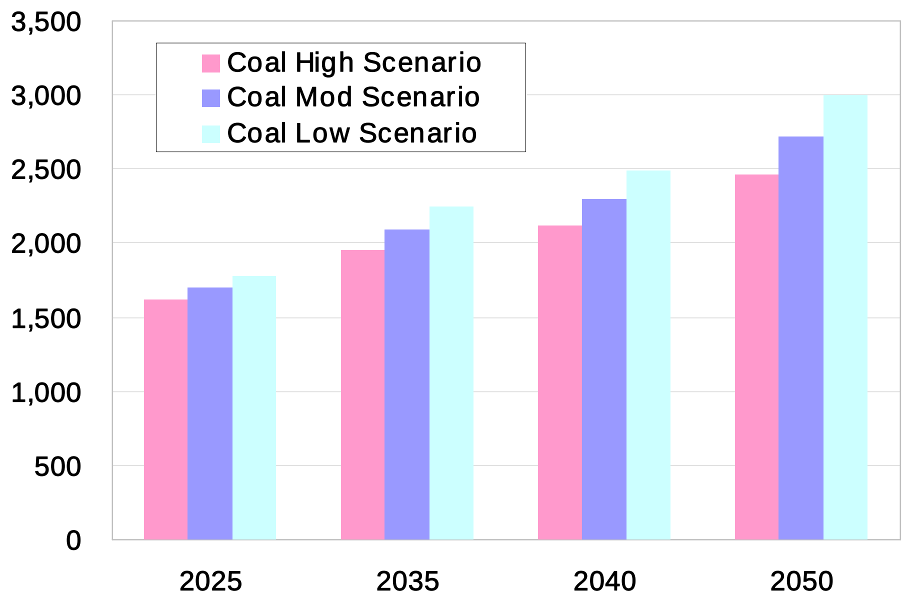


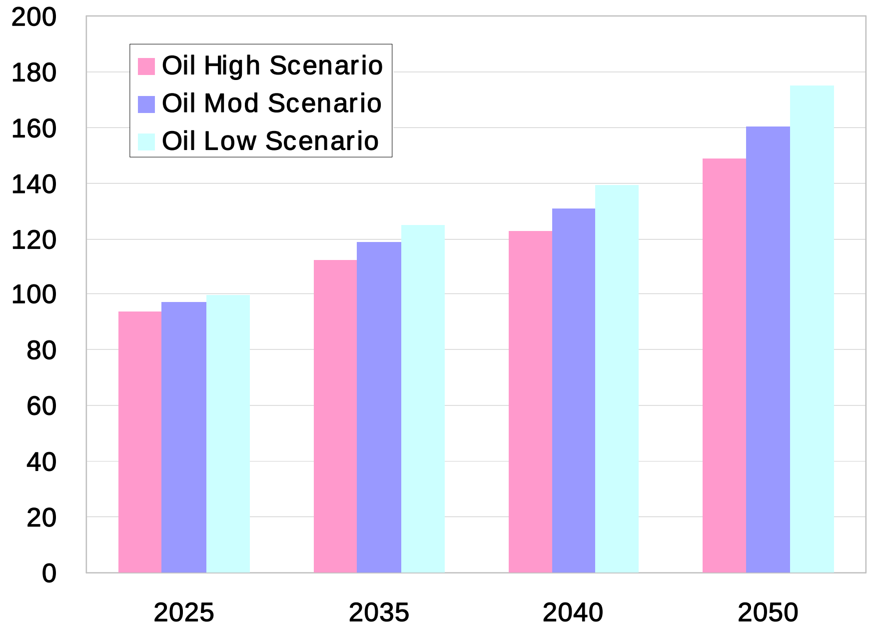
Figure 56 shows that coal used for power generation in APEC can be reduced by 18 percent on a yearly basis in the High nuclear scenario by the year 2050 relative to the Low scenario, while the reduction in the Moderate scenario in the same year can be equal to 9 percent also with respect to that used in the Low scenario.

Figure 56 Coal consumption for power generation in APEC in the Low, Moderate and High Nuclear Development Scenarios (Mtoe)



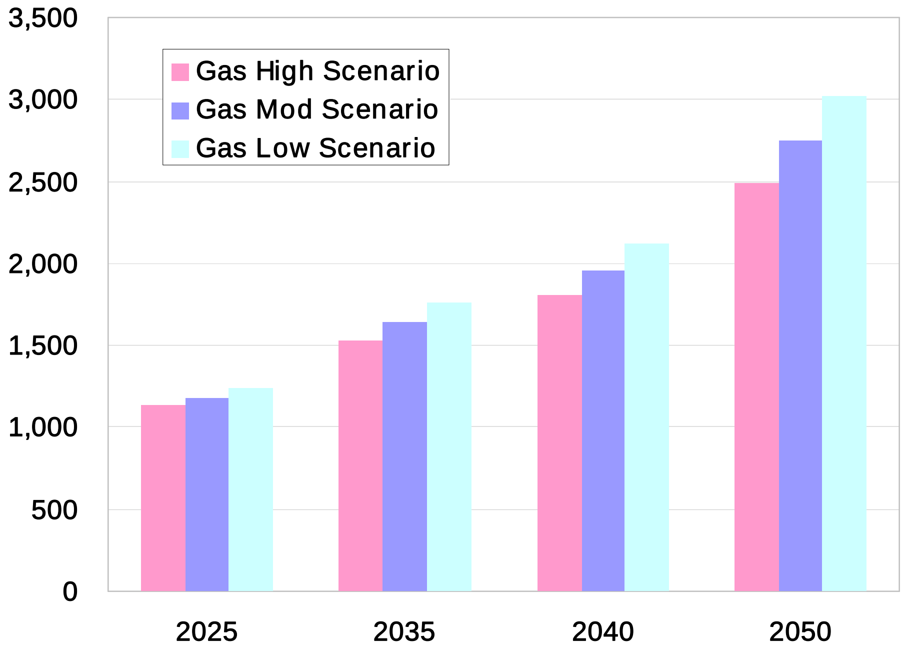
The amount of oil used for power generation per year in APEC is reduced in the High nuclear development scenario by 15 percent in the year 2050 relative to the Low nuclear scenario; and by 8 percent in the Moderate nuclear scenario (Figure 57). As seen before in Figure 55, the amounts of oil used for power generation are minimal compared to coal or natural gas.

Figure 57 Oil consumption for power generation in APEC in the Low, Moderate and High Nuclear Development Scenarios (Mtoe)



For natural gas (Figure 58), the reduction in the amount used yearly for power generation in all of APEC can reach 17 percent by the year 2050 in the High nuclear development scenario as compared to the Low nuclear development scenario. The percentage reduction in the Moderate nuclear development scenario is 9 percent also by the year 2050.

Figure 58 Natural gas consumption for power generation in APEC in the Low, Moderate and High Nuclear Development Scenarios (Mtoe)



ENERGY SECURITY

Fuel savings attained from the expanded use of nuclear power also contribute to improving energy security in the region. Just how much of a contribution we can expect to gain in terms of energy security from an expanded use of nuclear power can be assessed by comparing the fuel savings to fuel supply and to fuel imports in APEC.

Figure 59 Annual coal savings in APEC in the High and Moderate Nuclear Development Scenarios (Mtoe)

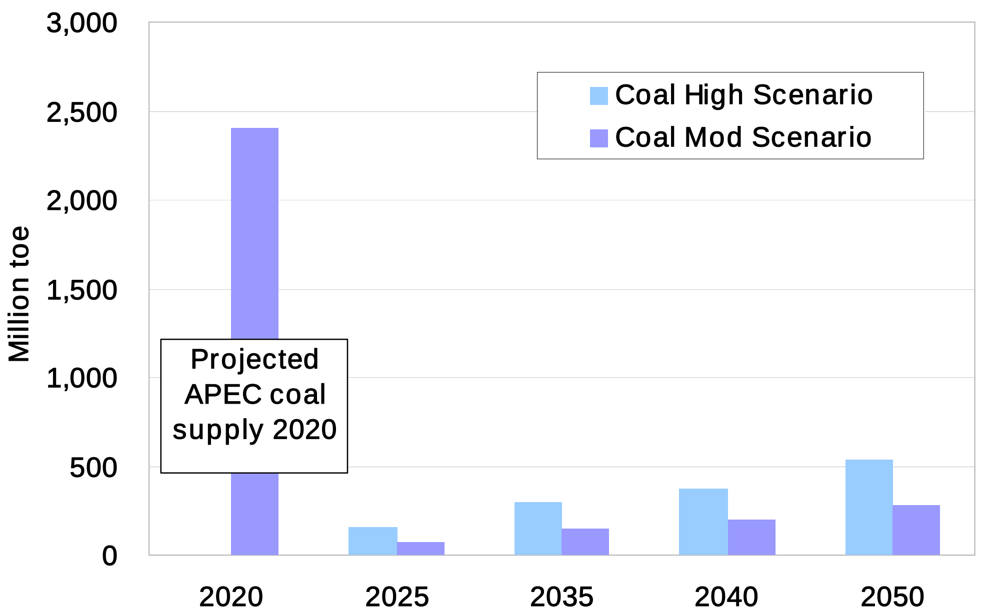
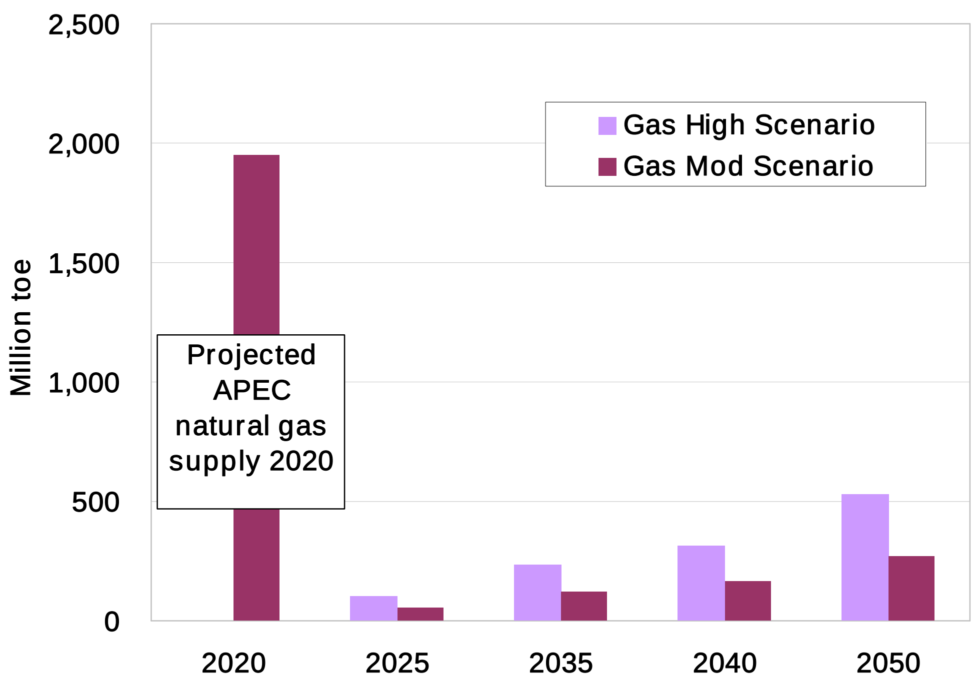


Figure 60 Annual natural gas savings in APEC in the High and Moderate Nuclear Development Scenarios (Mtoe)



The following graphs compare fuel savings to fossil fuel supply in APEC in the year 2020 as projected in our last APEC Outlook 2002. The fuel savings, as before, are the fossil fuels displaced in power generation due to an expanded use of nuclear power in the Moderate and High nuclear development scenarios, relative to the fossil fuels used in the Low nuclear development scenario. Coal displaced annually by nuclear power in the High nuclear scenario in the year 2050 amounts to 23 percent of the total supply of coal projected for the whole of APEC in the year 2020. Coal displaced in the Moderate scenario represents 12 percent of that same supply (Figure 59).

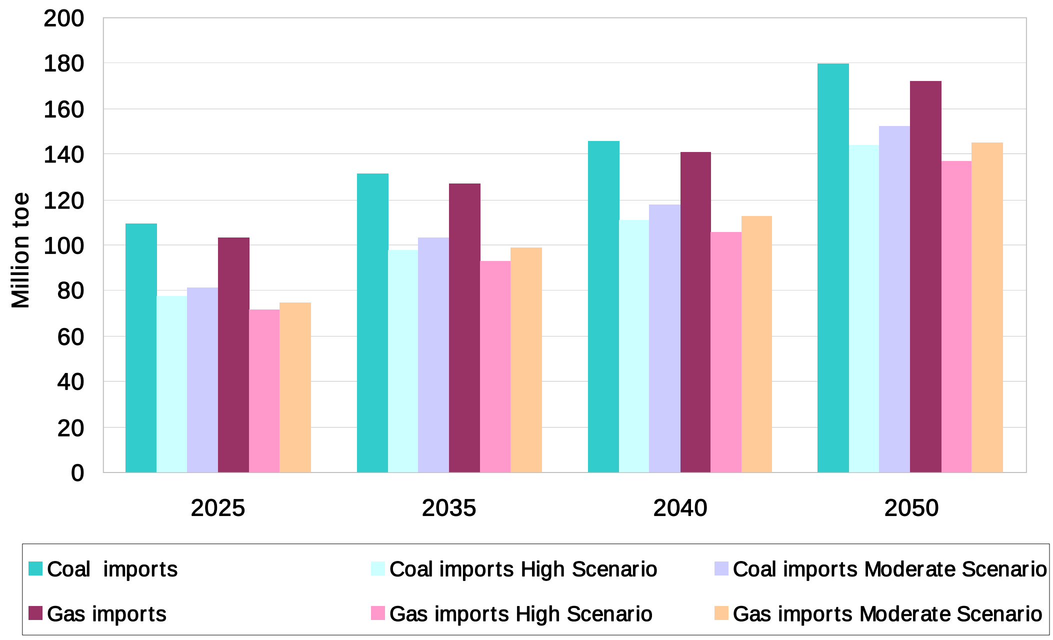
For natural gas, the annual savings in the High and Moderate scenarios by the year 2050 represent respectively 27 and 14 percent of the total supply of natural gas projected for the year 2020 in the APEC region (Figure 60). Oil quantities saved by the use of nuclear power do not contribute significantly to reduce the supply of oil in APEC as the bulk of this fuel is expected to be used in the transportation sector in the future.

IMPACT ON ENERGY SECURITY: JAPAN AND KOREA

For economies that have a high dependence on imported fossil fuels for power generation, even small contributions to reducing dependency acquire a high strategic significance. We analyse two cases in APEC: Japan and Korea, which depend on imports for around 80 percent of their primary energy supply.

To recapitulate, in the High nuclear development scenario Japan follows a policy of maintaining at least a 30 percent share of power generation coming from nuclear, which requires the replacement of all reactors that reach the end of their lifetime, plus the additional construction of roughly half of the installed capacity existing today. In the Moderate scenario, the assumption for Japan is only to replace reactors that are retired, maintaining the same level of generation and resulting in a nuclear share of 23 percent in the power generation mix by the year 2050.

Figure 61 Projected coal and gas imports compared to reduced imports due to the use of nuclear power in the High and Moderate scenarios in Japan, 2025-2050 (Mtoe)



For Korea, the assumption in the High nuclear development scenario is to maintain a minimum of 35 percent of share from nuclear energy in the generation fuel portfolio, which translates to a tripling in the current installed capacity by the year 2050. For the Moderate scenario, the assumption is for

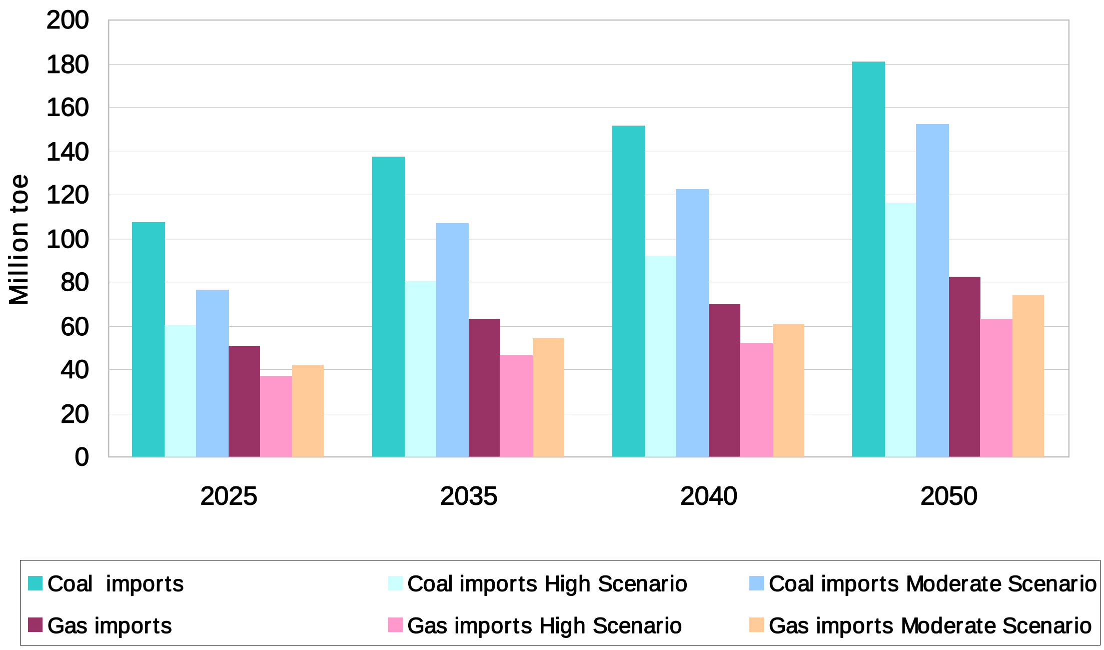
Korea to maintain the same level of generation coming from nuclear plants; in other words, to replace all nuclear plants when they reach their retirement age and not construct any other. This policy results in a nuclear share of around 15 percent of the total power generation mix by 2050.

In Figure 61 we make a projection of coal and natural gas imports for Japan for the 50-year period following the trends observed between 2000 and 2020 in our APERC Outlook 2002, and compare them to the reduced imports resulting from the cutback in the use of each fossil fuel in the High and Moderate nuclear development scenarios. It is important to note that in these next two Figures (for Japan and Korea), fossil fuel savings correspond to the fossil fuels displaced by the whole use of nuclear power, not the fuels displaced by the increased use of nuclear power between the Low and the other scenarios. In other words, fossil fuel displacement is measured relative to a 'zero use' of nuclear power, not to the assumed nuclear power base existing in the Low nuclear development scenario.

As can be seen in the figure, by the year 2050 the use of nuclear power in Japan can help reduce annual imports of coal by 19.7 percent in the High nuclear scenario, and by 15.1 percent in the Moderate scenario. Natural gas annual imports in 2050 on the other hand, can be reduced by 20.7 percent in the High scenario and by 15.9 percent in the Moderate scenario.

Coal displaced annually by nuclear power in Japan in the Moderate scenario in 2050 amounts to 27 million toe, or 41 million tonnes of coal. That sum represents around 28 percent of the total coal imports in Japan in the year 2002. For the High scenario, the amount by 2050 is 35 million toe per year and it represents 37 percent of the coal imported in 2002. As for natural gas, the amount avoided annually by the use of nuclear power in 2050 in the Moderate scenario is 27 million toe or close to 30 bcm which is equal to 44 percent of the total natural gas imported to Japan in the year 2002. In the High scenario the natural gas avoided in the year 2050 in Japan is 36 million toe and represents 57 percent of the imports of natural gas in 2002.

Figure 62 Projected coal and gas imports compared to reduced imports due to the use of nuclear power in the High and Moderate scenarios in Korea, 2025-2050 (Mtoe)



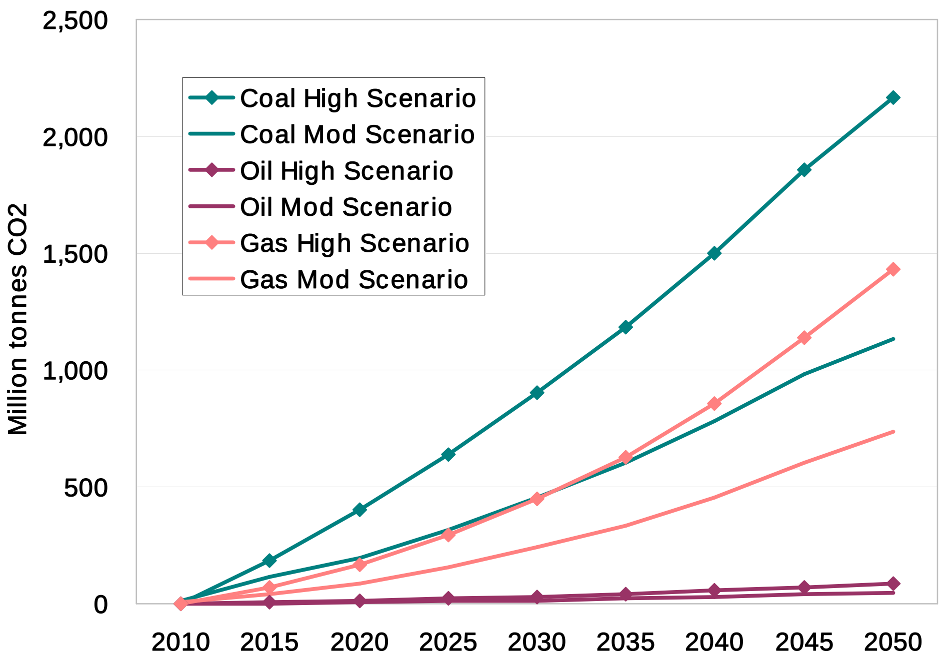
Projections of coal and natural gas imports are made also for Korea and compared to the reduced imports due to fossil fuels displaced by nuclear power in the High and Moderate scenarios (Figure 62). In this case as much as 35.7 percent of coal imports can be reduced annually in Korea by 2050 with the use of nuclear power at the level assumed in the High scenario. In the Moderate scenario, the imports of coal by the year 2050 can be reduced yearly by 15.7 percent. The installed nuclear capacity in the High scenario displaces enough natural gas to reduce the projected annual imports of this fuel in the year 2050 by 23 percent. In the Moderate case the reduction in annual imports is 10.2 percent.

The amount of coal displaced by nuclear power in the Moderate scenario in 2050 in Korea is 28.5 million toe, equal to 43 million tonnes of coal or roughly equal to 67 percent of all the coal imported by Korea in 2002. In the High nuclear scenario coal displaced is 64.7 million toe, or 97 million tonnes of coal which is equal to one and a half times that same amount imported in 2002 by Korea. Similarly, avoided natural gas in the Moderate nuclear development scenario in 2050 is approximately 9 bcm which represents 41 percent of the gas imports in Korea in 2002, while that avoided in the High scenario equals 21 bcm and represents roughly 93 percent of the imports in 2002.

CO_2 EMISSIONS

The following figures show the avoided emissions in tonnes of CO_2 (t CO_2) resulting from the reduced use of fossil fuels in power generation in APEC in the next 50 years. Figure 63 shows the annual avoided emissions arising from the reduced use of coal, oil and natural gas in power generation in both the High and Moderate nuclear scenarios relative to the Low Nuclear Development Scenario. The avoided CO_2 emissions from displacing coal amount to 2,168 million t CO_2 per year by 2050 in the High nuclear scenario and to 1,131 million t CO_2 in the Moderate nuclear scenario. For natural gas, the annual avoided emissions are 1,430 million t CO_2 by 2050 in the High scenario and 737 million t CO_2 yearly by 2050 in the Moderate scenario. As can be seen in Table 51, the avoided emissions coming from the three fossil fuels total a yearly figure of 480 million t CO_2 by 2025, and a yearly 1,917 million t CO_2 by 2050 in the Moderate nuclear development scenario. This is approximately equal to the 2,220 million t CO_2 avoided each year by all the nuclear plants existing in the world today, and approximately twice the amount of emissions that the IAEA estimates will be avoided by the Kyoto Protocol in 2010.[233]

Figure 63 Annual avoided CO_2 emissions from reduced use of fossil fuels in power generation in the High and Moderate Nuclear Development Scenarios (Million tonnes of CO_2)



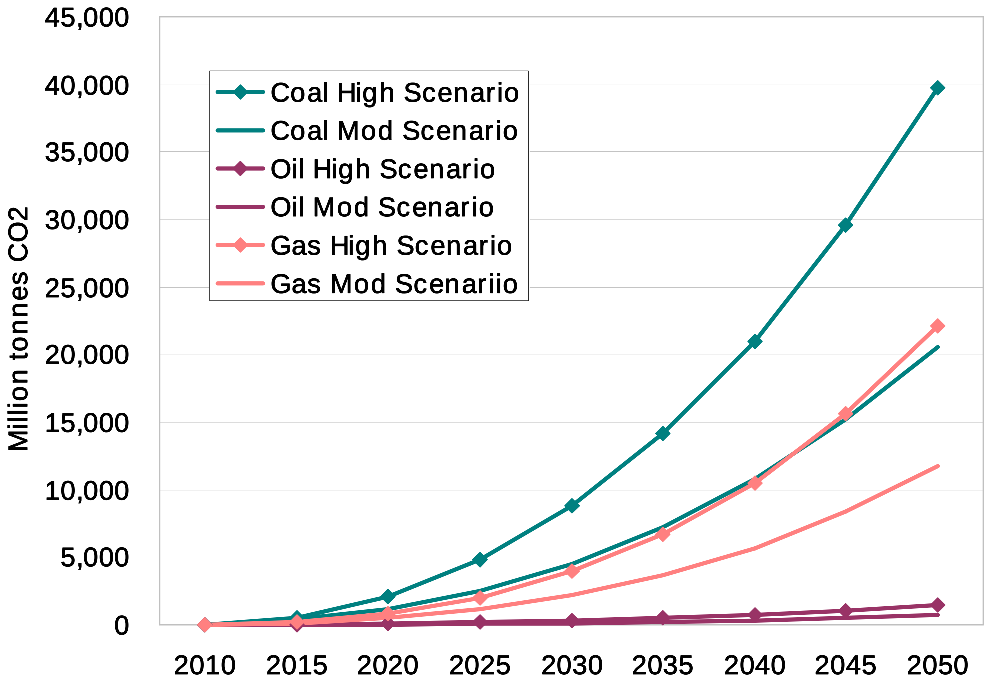
233 IAEA (2004e).

Table 51 Avoided CO_2 emissions from fossil fuel savings in power generation in APEC (Million tonnes of CO_2)

	2010 (Mt CO_2)	2025 (Mt CO_2)	2050 (Mt CO_2)
High nuclear case			
Coal	2.7	639.0	2,167.9
Oil	1.5	20.6	86.8
Natural gas	2.2	292.2	1,430.0
Total annual	6.5	951.7	3,684.7
Cumulative	13.0	7,025.1	63,327.1
Moderate nuclear case			
Coal	9.5	314.8	1,131.3
Oil	0.7	8.9	48.8
Natural gas	7.7	156.2	736.9
Total annual	17.8	479.9	1,917.0
Cumulative	50.9	3,716.5	33,112.1

Figure 64 shows the avoided emissions from the reduced use of the same three fossil fuels accumulated over the 50-year period, also for both the High and Moderate nuclear scenarios. The total avoided emissions stemming from all fossil fuels savings in power generation in APEC in the Moderate nuclear scenario amount to 33,112 million tonnes of CO_2 in 2050, while the total for the High nuclear scenario is 63,327 million tonnes of CO_2 by 2050.

Figure 64 Cumulative avoided CO_2 emissions from reduced use of fossil fuels in power generation in the High and Moderate Nuclear Development Scenarios (Million tonnes of CO_2)



A monetary cost can be attached to the previous CO_2 quantities for reference. Assuming a value of US$ 20 per tonne of CO_2 would render, for the Moderate scenario, an annual sum of US$ 38 Billion by the year 2050. For the High nuclear development scenario, the equivalent cost of avoided CO_2 emissions resulting from the displacement of fossil fuels in power generation would equal a yearly figure of US$ 74 Billion also by the year 2050.

CONCLUSION

The scenarios engineered for this exercise show that the contribution of nuclear power to the total power generation mix by the middle of this century can be of around 11 and 19 percent, requiring nuclear plant construction plans that can be considered modest as compared to those that will be required for coal- and natural gas-fired plants. The construction rate in the High development case for APEC economies goes from 2 plants per decade in the economies with the smallest programmes, to 35 plants per decade in the case of the United States. This is not overly ambitious considering that the United States by the mid point of the century will be required to construct around 82 natural gas-fired combined cycle plants (of 350 MW each) every decade. And assuming that the construction costs of new nuclear plants can be brought down as the manufacturers expect, the cost of constructing the required nuclear plants will be comparable to the construction of similarly sized advanced coal-fired plants.

The advantages of doing this would be noteworthy gains in terms of fossil fuel savings, reductions in fossil fuel imports, and important reductions in contaminating emissions, strengthening energy security and sustainable development in the region.

As for displacing fossil fuels, the APEC region as a whole can do away with 15 to 18 percent of the annual consumption of coal, natural gas and oil in power generation in the High nuclear development scenario by the year 2050 relative to the Low development scenario. That figure would be of around 8-9 percent in the Moderate development scenario. The ultimate benefit that these savings will represent to each individual economy will depend of each economy's given characteristics in terms of fuel prices and fuel availability.

For energy importing economies, fuel savings help reduce foreign dependency. It was shown that Japan can reduce its foreign dependency on coal by the year 2050 by anywhere between 15 and 20 percent depending on the nuclear development scenario, and its natural gas foreign dependency by between 16 to 21 percent. Similarly for the case of Korea, where its dependence on imported coal by the year 2050 can be reduced by 16 to 36 percent on a yearly basis dependent on the scenario chosen, and the dependence on imported natural gas can also be reduced by 10 to 23 percent. Whether those amounts are significant to these economies in terms of import policies depends on how each economy values fuel independence. The results show that with nuclear power shares in electricity generation by the year 2050 of 15 percent for Korea and 23 percent for Japan, dependence on imported fuel can be reduced by around 15 to 20 percent. Achieving lower dependence on energy imports will require having nuclear power shares in electricity generation higher than those assumed under the Moderate nuclear development scenario.

The gains in terms of avoided CO_2 emissions are more significant and can have a definite impact in the future of climate change control. As mentioned before, the Kyoto Protocol expects to reduce annual CO_2 emissions by roughly 1,000 million tonnes by the year 2010 with the current number of ratifications. Expanding the installed nuclear capacity in APEC from the level considered in the Low development scenario to the levels of the Moderate and High scenarios, can contribute to the avoidance of between 480 and 1,917 million tonnes of CO_2 emissions annually by the year 2050.

CONCLUSIONS

Nuclear energy and its contribution to energy systems deserve to be re-evaluated. It is easy to disqualify nuclear energy too readily as a hazardous, uneconomic and overly complicated technology, but by doing so we might negate ourselves of what could be an indispensable energy source. In view of the world's rapidly increasing energy demand and the reduced number of environmentally sound and dependable options to meet such demand in the future, nuclear power stands as a viable option.

There is an overstatement of nuclear energy's drawbacks; especially over issues such as safety, waste, and economics. Fears about nuclear power's safety are not necessarily well justified. Since its beginnings in the 1950s it has proven to be the safest of all energy sources, even considering the one single accident, Chernobyl. Safety records in the operation of nuclear plants are improving and nuclear reactors in the future can be made even safer as more safety features are being incorporated into new designs.

The public perception of nuclear waste as being an 'unsolvable' problem is unfounded from a technological standpoint. Waste in the nuclear industry is but a small fraction of the burden that industrial waste represents worldwide, with the difference that nuclear waste decays to safe radioactive levels over time. As was seen in Chapter 5: Waste Management, there is no urgent need at present for final disposal of high level radioactive waste given that mostly all is undergoing the required 40-50 year initial cooling down period. When sufficient volumes of spent fuel assemblies or of high-level waste are ready to be definitively disposed of, the technology for deep underground repositories will have been demonstrated and available. The technology is well advanced today and there is already one repository for military use in operation in the United States. The construction of the first civilian repository is expected sometime after 2010.

Economics today are not favourable for nuclear power, but that can change in the future. Operating costs have proven to be competitive in liberalised electricity markets. Competitiveness of new nuclear plants has a good chance of improving with the lower prices announced by vendors for new models, with revised licensing procedures, with shorter lead-times for construction, and with the aid from local governments in the form of tax breaks or with risk sharing. And that is without counting the benefits to be obtained by external factors such as the expected increases in fossil fuel prices in the future, or the seemingly imminent implementation of carbon control and trading schemes.

Also, there is an understatement of nuclear energy's benefits. Many important concerns presently existing in APEC can be addressed by nuclear power. The drivers of nuclear power in APEC reflect those concerns: scarcity of local energy resources, the need for energy diversification to meet electricity demand, and the need to reduce pollutant emissions. Nuclear power as a baseload energy source significantly reduces reliance on fossil fuels. Heavy dependence on fossil fuels means also vulnerability to fuel price increases and volatility. Nuclear plant fuel prices are lower than for alternative fossil fuels, have a history of stability, and because of the low contribution of uranium price to total generation costs, it is much less vulnerable to fuel price volatility. And nuclear power is the only large-scale, baseload energy source besides hydro that does not emit greenhouse gases while capable of generating massive amounts of needed electricity. In the quest for large-scale sustainable energy sources it is one of few credible choices.

A comprehensive assessment of benefits and drawbacks of nuclear power might result in the benefits outweighing the drawbacks in a number of cases in APEC economies. Also, an evaluation pairing nuclear power against other energy options can render it more attractive than the alternatives in some cases in the APEC region.

But for nuclear power to have a prominent position in the electricity generation scene, advances have to be made on the most controversial issues. The industry has to prove that investment cost reductions are possible and has to eliminate the public's scepticism concerning nuclear waste handling by constructing and demonstrating at least one civilian waste repository.

On the part of governments, it will entail major responsibilities to ensure the continued safe operation of nuclear facilities, to make the required political decisions to develop and implement national waste management strategies, and to promote international action to strengthen non-proliferation controls.

NUCLEAR POWER FUTURES IN APEC

APEC in general is the region with the largest concentration of nuclear plants in the world. The Asian region of APEC in particular, is the one with the most expansion activity today. Nuclear power will therefore continue to be a major part of electricity generation in the area for the short to mid-term future.

The question is if during the next 50 years its contribution will remain the same, or if it will expand, or contract. In our estimation, after studying the policies and drivers for nuclear power in APEC, and after the analysis of the key issues influencing the future of the nuclear industry, we conclude that the most likely path for nuclear energy in APEC will lie between the two upper scenarios shown in the projections in this report:

- The moderate nuclear development scenario in which the total generation by nuclear power increases by 182 percent but its share in total generation decreases from 16 percent today to 11 percent in 2050; and
- The higher nuclear development scenario in which total generation by nuclear power quadruples to 2050 and its contribution to total generation increases from 16 percent today to 19 percent by the same year.

The use of nuclear reactors to generate electricity in this way will result in fossil fuel savings of between 9 and 18 percent relative to the low nuclear development scenario.

Avoided CO_2 emissions can have a definite impact in the future of climate change control. Expanding the installed nuclear capacity in APEC from the level considered in the low development scenario to the levels of the moderate and high scenarios, can contribute to the avoidance of between 0.5 and 1.9 billion tonnes of CO_2 emissions annually by the year 2050. For comparison, the total amount of emissions that will be avoided by the Kyoto Protocol in 2010 is roughly around 1 billion tonnes of CO_2.

COLLABORATION POSSIBILITIES IN APEC

Nuclear energy, embodying sophisticated and resource intensive technologies, presents different opportunities for collaboration among APEC member economies. As explained on Chapter 5: Waste Management, there are possibilities in the area of waste technology, including firstly a multinational regional deep geological repository that in view of the technical, political and financial difficulties in their construction would make economic and practical sense to build jointly by several member economies. However, political and legal barriers will have to be overcome before one becomes a reality. Other less ambitious projects could count collaboration on high level waste technology research, design and operation of LILW surface storage installations, LILW processing and preparation methods, waste standards and licensing, capacity building, and even the joint construction and operation of an underground research laboratory.

And there certainly are other areas for collaboration outside the realm of waste management. Among the various possibilities are: international collaboration on reactor technology development, centralised international fuel cycle services, and development of nuclear licensing procedures and regulation. Collaboration on reactor technology development could focus on reactor designs of regional interest and be set up along the lines of the United States' Generation IV International Forum or the IAEA's INPRO programme.

The need to prevent nuclear proliferation merits a closer look at the centralisation of different stages of the nuclear fuel cycle. Industrialised economies with nuclear power capabilities could offer commercially, at a regional level, fuel services such as uranium processing, enrichment, fuel manufacturing, and spent fuel handling to other economies in the area planning small nuclear programmes that do not warrant the investment in such resource intensive activities. This can contribute to prevent the spread of sensitive technology and ensure supply to legitimate users with advantages to all involved in cost, safety, and security.

An important area for international collaboration is communication and social acceptance. In modern democratic societies, nuclear energy policy will be increasingly influenced by public opinion. Public acceptance of nuclear power requires working towards two main goals: public education on matters related to nuclear energy's risks and benefits as compared to other energy sources; and public involvement in the decision-making process. Collaboration efforts could be directed at developing methods for the exchange of information. There is a need for more efficient information exchange processes between stakeholders including industry, governments and the public; both for educating the public on general nuclear energy culture and for the prompt transmission of relevant information regarding incidents at nuclear facilities, licensing processes, decisions on new constructions, or other current events. Another form of valuable cooperation is the sharing of information and experiences. The analysis of practical experiences in different member economies could provide opportunities to draw lessons from successful as well as non-successful practices. In this regard, evaluations can be made jointly to determine and eventually establish the best new methods for public participation that increase the trust and transparency in policy-making.

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