Energy Portfolios

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Preface

The International Energy Agency, Paris, has been vigorously advocating the view that, "a global revolution is needed in ways that energy is supplied and used", in order to limit the global temperature increase to 2.0–2.4°C above the pre-industrial temperature. In 2008, in the context of the current disastrous slump in the global economy, the promise of jobs is a stronger incentive to go green than the threat of ice caps melting and coastal cities drowning in 2018 or 2048. An attractive attribute of these green jobs is that most of them cannot be outsourced. France again leads the world in innovative energy approaches. Earlier, the massive construction of nuclear reactors fundamentally changed the energy economy of France (see Chap. 5.3 in this volume). Now France has launched a massive greening programme, starting with in the construction business. About 25% the country's greenhouse-gas emissions come from energy consumption in the buildings. About 200,000 to 500,000 jobs are expected to be created in the process of bringing about a 40% drop in the energy consumption in the construction sector by 2020, involving investment of hundreds of millions of euros.

This volume seeks to provide the knowledge base to facilitate making informed choices in regard to energy sourcing and energy technologies to achieve a job-led, low-carbon economic growth.

It is the energy use that has made the modern life (automobiles, communications, food, health, entertainment, etc.) possible. Energy has emerged as one of the most important issues of the twenty-first century. Each pathway of energy generation is characterized by its own combination of economic, technical, social, climate change, and environmental consequences. Each country has to figure out its own energy portfolio, consistent with its endowment of energy resources, and employing technologies, which are economically viable and socially equitable, and have minimal adverse impacts. As the continued use of fossil fuels for electricity generation and transportation has ominous implications for climate change and the environment, generation of nuclear power is emerging as an effective strategy to stabilize the CO_2 emissions. There is, however, no silver bullet to achieve reduction of CO_2 emissions in one go, for the simple reason that energy choices we make for each kind of energy use (e.g. transportation, domestic use, manufacturing, agriculture) require different kinds of solutions for reducing the CO_2 emissions.

The global economy is projected to grow four-fold between now and 2050, and there could be ten-fold growth in the case of some developing countries, such as India and China. This would inevitably involve much greater use of energy. Such a development will bring about profound improvements in the economic productivity and quality of life of the people in developing countries (for instance, India's electricity demand per capita in 2005 has been 639 kWh (as against 8870 kWh per capita in OECD countries), and about 40% of Indians have no access to electricity. Power generation is expected to grow to 1900 kWh per capita in 2030. Greater energy use would entail unsustainable pressure on natural resources (such as fossil fuels) and unacceptable degradation of environment (it is said that China has twenty out of thirty most polluted cities in the world, because of coal use). Decoupling economic growth from energy demand, and reduction in the use of fossil fuels, are the two principal ways by which the adverse outcome could be avoided. Improvements in the energy economy are sought to be accomplished through greater energy efficiency, greater use of renewable and nuclear power, CO_2 Capture and Storage (CCS) on a massive scale, and development of carbon-free transport.

The International Energy Agency (2008) came up with two sets of scenarios, which are referred to in the volume:

1. ACT scenarios which makes use of technologies that already exist or likely to be available soon, to bring the CO_2 emissions back to current levels by 2050. Emissions need to peak between 2020 and 2030, costing USD 50 per tonne of CO_2 saved when fully commercialized.
2. Blue scenarios, whereby emissions must be reduced by 50–85% of the current levels by 2050, in order for the global warming to be confined to the IPCC-recommended figure of 2°C–2.4°C. This is more expensive than ACT scenarios as it involves the deployment of technologies which are yet to be developed.

The volume has Sections for Coal, Oil and Natural Gas, Nuclear Power, Renewable Energy Resources, and Quo vadis? Conversion constants, abbreviations, acronyms and definitions are given elsewhere in the volume. The focus of the volume is on how to use technologies to optimize the energy productivity of, and reduce the carbon emissions and adverse environmental and health effects from, a given energy source. Country studies have been given for principal energy sources.

I am grateful to Prof. Anny Cazenave for her perceptive Foreword. Despite her scientific eminence, she is modest, simple, approachable and helpful – she indeed wears her greatness lightly. Drs. T. Harikrishnan, K.S. Murti, and Subhas Tella kindly reviewed the manuscript, and made useful suggestions. Y. Ramamohan and S. Srinivas provided computer assistance. The solicitous care by my wife, Vijayalakshmi, aided by our kind neighbour, Mrs. Satya Kalluri, kept me in good health. By a happy coincidence, the issuance of the volume coincided with the birth of my grandson, Govind (named after the great Sikh *guru*).

Suzlon Energy kindly permitted the use of a photograph of their wind farm, on the cover of the book.

The volume will be useful to university students, administrators and professionals in the areas of resource engineering, energy industries, environmental science and engineering, economics, climate change, etc.

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November 2008

Foreword

The well being and productivity of a family, a community or a country are critically dependent upon secure, reliable and affordable energy supplies. The global energy paradigm has to simultaneously address two linked issues, namely, economic growth of growing populations on the one hand and the mitigation of climate change on the other. The world population is expected to increase from about 6.5 billion in 2005 to about 9.2 billion in 2050, with India (with 1.66 billion) emerging as the most populous country in the world by then. The International Energy Agency, Paris, estimates that between now and 2050, the global economy is projected to grow four-fold, while the economies of China and India will grow ten-fold. This will inevitably involve greater use of energy, higher emissions of carbon dioxide, and global warming. Five countries (USA, China, Russia, Japan and India, in that order) currently account for 55% of the global energy-related carbon dioxide emissions. The same five countries will remain the top CO_2 emitters in 2030 also, though their relative ranks will change (China will be the largest emitter).

Decarbonisation is the energy mantra for stabilizing CO_2 emissions in the 445–490 ppm CO_2-equivalent, corresponding to the increase of 2.0–2.4°C above the pre-industrial temperature. Power sector is sought to be decarbonised using CCS in a massive way. Use of low carbon footprint biofuels and improvements in the efficiency of conventional vehicles, will reduce the carbon emissions in the transport sector. Decarbonisation measures in the buildings and the appliances sector include the design of building-shell measures, heat pumps, solar heating, use of high-efficiency appliances and lighting, shifting to renewable, low-carbon electricity, etc.

The volume provides detailed information on the optimal size, capital costs, operation and maintenance costs of power plants, their adverse environmental and health consequences and ways of mitigating them, etc. in respect of the a number of low-carbon energy options: Coal-fired with CCS, Nuclear Power, Hydropower, Biomass plants, Wind- onshore, Wind – offshore, Geothermal power, Solar PV and Solar CSP.

Thus, individual countries can make use of the above information to customize their energy portfolios by choosing the precise mix of CCS, renewables and nuclear technology to decarbonise the power sector, in consonance with their resource endowment, and biophysical and socioeconomic environments. Almost any country or region in the world can make use of one option or another. For instance, in remote areas which are not connected to the grid, solar lanterns can be used for lighting. *Jatropha curcas* trees can be grown in waste lands which are unsuitable for crop cultivation, and the biodiesel obtained from its seeds can be used to run motors and as a fuel in vehicles. This provides both energy and employment to villagers.

A massive Research and Development, Demonstration and Deployment effort will be needed to bring down costs, and improve efficiencies of the emerging energy technologies. Also, the science base and its links with technology need to be improved through the promotion of basic sciences, such as, geology, physics, chemistry, materials science, biochemistry, nanotechnology, applied mathematics, etc. The present volume will be of great use in this effort.

Dr. Aswathanarayana's earlier writings on food, water and environmental security have the great merit of bringing together a variety of techno-socio-economic approaches to focus on the core theme. He continued with the same approach in the case of the present volume too – I admire the way he explains two disparate technologies, such as, the Supercritical Pulverized Coal Combustion and Vitrification of High Level Nuclear Waste, with the same lucidity and ease.

University students, professionals and administrators in both the Industrialized countries and the Developing countries will find this modern and comprehensive volume on Energy a great read.

I wish Dr. Aswathanarayana a long and productive writing career (he is now in his 81st. year).

Anny Cazenave
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November 2008

Abbreviations and Acronyms

AFC – Alkaline Fuel Cell
API – American Petroleum Institute
APU – Auxiliary Power Unit
ASU – Air Separation Unit
ATR – Auto Thermal Reforming
BEMS – Building Energy Management System
BFB – Bubbling Fluidised Bed
BIGCC – Biomass Integrated Gasification with Combined Cycle
BtL – Biomass to Liquids
CAES – Compressed Air Energy Storage System
CAT – Carbon Abatement Technologies
CBM – Coal-Bed Methane
CCS – CO_2 Capture and Storage
CDM – Clean Development Mechanism
CdTe – Cadmium Telluride
CFB – Circulating Fluidised Beds
CFL – Compact Fluorescent Light-bulb
CHP – Combined Heat and Power
CIS – Copper-Indium – Diselenide
CIGS – Gallium-doped Copper – Indium – Diselenide
CNG – Compressed Natural Gas
CSP – Concentrating Solar Power
CTL – Coal To Liquids
DME – Dimethyl Ether
EGR – Enhanced Gas Recovery
EIA – Environment Impact Assessment
FBC – Fluidised Bed Combustion
FDI – Foreign Direct Investment
FGD – Flue Gas Desulphurisation
HTGR – High Temperature Gas Cooled Reactor
IAEA – International Atomic Energy Agency
IEA – International Energy Agency
IET – International Emissions Trading
IGCC – Integrated Gasification Combined Cycle
IGFC – Integrated Gasification Fuel cell combined Cycle

ITER – International Thermonuclear Experimental Reactor
LED – Light Emitting Diode
NEA – Nuclear Energy Agency
NGL – Natural Gas Liquids
NSG – Nuclear Suppliers Group
O&M – Operating and Maintenance
OECD – Organisation for Economic Cooperation and Development
OPEC – Organization of Petroleum Exporting Countries
PFBC – Pressurised Fluidised Bed Combustion
PM-10 – Particulate matter of less than ten microns in diameter
PPP – Purchasing Power Parity
P&T – Partitioning and Transmutation
PV – Photovoltaics
PWR – Pressurised Water Reactor
RDD&D – Research, Development, Demonstration and Deployment
RET – Renewable Energy Technologies
SACS – Saline Aquifer CO_2 Storage
SCSC – Supercritical Steam Cycle
SMR – Small and Medium-sized Reactor
T&D – Transmission and Distribution
USCSC – Ultra Super Critical Steam Cycle
VHTR – Very High Temperature Reactor

Fuel and Process Definitions (source: IEA)

"API Gravity: Specific gravity measured in degrees on the American Petroleum Institute scale. The higher the number, the lower the density. Twentyfive degrees API equals 0.904 kg/m^3. Forty-two degrees API equals 0.815 kg/m^3.

Biodiesel: Biodiesel is a diesel-equivalent, processed fuel made from the transesterification (a chemical process which removes the glycerine from the oil) of vegetable oils or animal fats.

Biogas: A mixture of methane and carbon dioxide produced by bacterial degradation of organic matter and used as fuel.

Black liquor: A by-product from chemical pulping processes which consists of lignin residue combined with water and the chemicals used for the extraction of lignin.

Clean Coal Technologies (CCT): Technologies designed to enhance the efficiency and the environmental acceptability of coal extraction, separation and use.

Coal: Lignite (with gross calorific value of less than 4165 kcal/kg), sub-bituminous coal (4165–5700 kcal/kg) and hard coal (greater than 5700 kcal/kg, on ash-free, but moist basis). Clean Coal Technologies (CCTs) are designed to enhance the efficiency and the environmental acceptability of coal extraction, preparation and use. Coal-bed methane is methane found in coal seams, and is a source of unconventional natural gas.

Condensates: Condensates are liquid hydrocarbon mixtures recovered from non-associated gas reservoirs. They are composed of C4 and higher carbon number hydrocarbons and normally have an API between 50° and 85°.

Enhanced Coal-bed Methane Recovery (ECBM): A technology for the recovery of methane through CO_2 injection into uneconomic coal seams.

Enhanced Gas Recovery (EGR): A speculative technology in which CO_2 is injected into a gas reservoir in order to increase the pressure in the reservoir, so that more gas can be extracted.

Ethanol: Ethanol is an alcohol made by fermenting any biomass high in carbohydrates (such as, starches and sugars). Emerging technologies will allow ethanol to be produced from cellulose and hemicellulose fibres that make up the bulk of the most plants.

Gas: Gas includes natural gas (both associated and non-associated with petroleum deposits but excluding natural gas liquids) and gas-works gas.

Gas-to-Liquids: Fischer-Tropsch technology is used to convert natural gas into synthetic gas (syngas) and then, through catalytic reforming or synthesis, into very clean conventional oil products, such as diesel.

Hydropower: Hydropower refers to the energy content of the electricity produced in hydropower plants, assuming 100% efficiency. It excludes output from pumped storage plants.

Natural Gas Liquids (NGLs): They are the liquid or liquefied hydrocarbons produced in the manufacture, purification and stabilization of natural gas. These are those portions of natural gas which are recovered as liquids in separators, field facilities, or gas-forming plants. NGLs include but not limited to ethane, propane, butane, pentane, natural gasoline and condensates.

Nuclear: Nuclear refers to the primary heat-equivalent of the electricity produced by a nuclear plant with an average thermal efficiency of 33 %.

Oil: Oil includes crude oil, condensates, natural gas liquids, refinery feedstocks, and additives and other hydrocarbons (including emulsified oils, synthetic crude oil, mineral oils extracted from bituminous minerals such as oil shale, bituminous sand, and oils from coal liquefaction) and petroleum products (refinery gas, ethane, LPG, aviation gasoline, motor gasoline, jet fuels, kerosene, gas/diesel oil, heavy fuel oil, naphtha, white spirit, lubricants, bitumen, paraffin waxes and petroleum coke).

Rest of Renewables: Includes biomass and waste, geothermal, solar PV, solar thermal, wind, tide, and wave energy for electricity and heat generation.

Electricity Generation: Total amount of electricity generated by power plants. It includes its own use, and transmission and distribution losses.

Power Generation: Refers to fuel use in electricity plants, heat plants, and combined heat and power (CHP) plants. Both main activity producer plants and small plants that produce fuel for their own use (autoproducers) are included.

Purchasing Power Parity (PPP): The rate of currency conversion that equalizes the purchasing power of different currencies, by making allowances for the differences in price levels and spending patterns between different countries.

Total Final Consumption (TFC): It is the sum of the consumption by the different end-use sectors: industry (including manufacturing and mining), transport, other (including residential, commercial and public services, agriculture/forestry and fishing), non-energy use (including petrochemical feedstocks), and non-specified.

Total Primary Energy Demand: Total Primary Energy Demand represents domestic demand only, including power generation, other energy sector, and total final consumption. It excludes international marine bunkers, except for world energy demand where it is included."

SECTION-I
Energy from coal

U. Aswathanarayana
India

PREAMBLE

The case of coal reminds us of the "rose-and-thorn" syndrome. For instance, countries like China, India, USA and Poland cannot avoid using coal for generating energy. The mining, preparation, transport and combustion of coal severely pollute the environment (not only in the countries concerned, but also in the neighboring countries), and causes climate change on a global-scale. This section draws attention to technologies for maximizing the efficient use of coal and minimizing the environmental impact and carbon emissions.

The Coal Cycle has serious environmental and health impacts. Technologies (detailed in this section) are available that minimize the health and environmental impact of dusts which are produced in the process of mining, preparation and transport of coal, and emissions which are generated in the process of combustion of coal, disposal of coal mine tailings and control of burning of waste tips, etc. Also, systematic application of proven technologies would result in improved rehabilitation of mined land, and in limiting the adverse effects of subsidence, flooding, explosions, roof collapse, etc.

China has emerged as an industrial giant, with USD 10 trillion economy in 2006, and there is little doubt that coal sector played an important role in the phenomenal growth of GDP (~11% in 2006) in the country. China accounts for more than half of the coal production in the world (2842 Mt, out of 5370 Mt). However, twenty out of thirty most polluted cities in the world are in China. The following steps that are being taken by China to improve the coal sector, are of general interest to the coal community in the world: (i) High degree of mechanization in coal mining designed to lead to high productivity per person-year (e.g. Shenua Group achieved the productivity of 30,000 t person-year), reduce hazards and fatalities, and increase recovery rate (to >45%), (ii) Dedicated rail lines, with trains capable of large payloads (25,000 t), (iii) Installation of Flue Gas Desulphurization (FGD) units to reduce noxious emissions, (iv) Improve energy efficiency in power generation, iron and steel, cement, fertilizer, etc. industries.

A number of power-generation technologies are being developed which are characterized by higher thermal efficiencies, and also lower emissions of NO_x and SO_2. These are: Supercritical and ultra-supercritical pulverized coal combustion (which can attain efficiencies of about 50%), Circulating Fluidized Bed Combustion (CFBC) (which allow for the *in situ* capture of SO_2), Integrated Gasification Combined Cycle (IGCC) from which CO_2 can be captured and stored, and hybrid systems, such as fuel cell-IGCC. Australia has succeeded in using a liquid for capturing 85% of Post-Combustion CO_2 (PCC). This break-through will benefit the future and present coal-fired power stations.

The Section draws extensively from the author's own works (Aswathanarayana, 1995, 2003) and the recent publication of the International Energy Agency (*World Energy Outlook 2007*).

1.1 COAL: ITS MODE OF FORMATION AND ECONOMIC IMPORTANCE

1.1.1 Formation of coal

Coals are formed from the accumulation of vegetable debris in specialized environments. They range in age from Upper Palaeozoic to Recent. The rank of coal (peat, lignite, sub-bituminous coal, bituminous coal, semi-anthracite and anthracite, in order of increasing rank) and the degree of structural complexity are determined by the synsedimentary and post-sedimentary processes to which the vegetable matter has been subjected. The coal-bearing sequences tend to be so similar that when once a lithofacies (say, a sandstone) of a particular sequence (say, a Gondwana cyclothem) are met with, it is possible to predict the existence of coal of a particular rank.

The greater the depth of burial, and the longer the length of burial, the higher would be the rank of coal. As Hilt's law states, "In a vertical sequence, at one locality in a coal field, the rank of the coal seams rises with increasing depth". The rate of rank increase depends upon the geothermal gradient and heat conductivity of rocks. Where the geothermal gradient is high (70–80°C/km), coal attains bituminous rank at depths of 1500 m (Upper Rhine graben, Germany), whereas in an area of lower gradient (40°C/km), coal is bituminous at a much greater depth of 2600 m (Thomas, 1992, p. 21). Thus, Palaeozoic coals tend to be bituminous and anthracitic, whereas Tertiary coals are generally lignitic.

Coal is formed in fluvial, deltaic and coastal barrier systems. The palaeo-depositional environments of coal are reconstructed on the basis of the study of the relationships between the changes in the lateral and vertical sequences and the depositional settings in the modern analogues of fluvial, deltaic and coastal barrier systems (Thomas, 1992, pp. 55–95).

1.1.2 Coal-bearing sedimentation sequences

Coastal barrier and back-barrier facies: The clean barrier sandstones become fine-grained in the seaward direction and grade landwards into dark grey lagoonal shales, and marginal swamp areas on which the vegetation was established. As the barrier sandstones have been constantly reworked, they tend to be more quartzose than the sandstones in the surrounding environments. In this sequence, upward-coarsening, organic-rich grey shales and siltstones are overlain by thin, discontinuous coals, with bands and concretions of chemical precipitation of sideritic ironstones. The sequences are generally 20–30 m thick, and 5–25 km in width.

Lower delta plain facies: The lower delta plain deposits are composed of mudstones and siltstones, ranging from 15 to 55 m in thickness and 8 to 110 km in lateral extent. Sandstones are common in the upper part of the sequence, indicating shallow water deposition. As the bays filled, plants grew abundantly, and these provided the vegetable debris needed for coals. Thick organic accumulations in the abandoned distributary channels resulted in the formation of lenticular coal deposits.

Upper delta and alluvial plain facies: Linear, lenticular sandstone bodies upto 25 m in thickness and width of 11 km, are characteristic of upper delta and alluvial facies. The massively bedded sandstones are overlain by siltstones. Coal seams in the upper delta plain facies are more than 10 m in thickness, but are of limited areal extent.

A special characteristic of the transition zone between the upper and the lower delta plain facies is the formation of peat mires on a widespread platform. The platform was cut by numerous channels, and there was development of crevasse-splay deposits. The coals formed on such a platform are thicker and more widespread than the coals of the lower delta plains (Thomas, 1992, p. 63).

As should be expected, the variations in the thickness of the coal seams are closely related to the pre-existing topography. The environment of deposition of, and syn-sedimentary and post-sedimentary changes in, a coal seam has a direct bearing on the thickness, quality and minability of the seam. Any rise in pressure (due to say, folding or faulting) or temperature (such as, due to igneous intrusions) could have the effect of raising the rank of coal.

Syndepositional changes: The combination of thick sediment accumulation and rapid basin subsidence could lead to slumping and load structures and liquefaction effects. Under such loading, coaly material may be squeezed into the overlying strata. Growth-faulting is common in the coal-bearing basinal sediments. The basement faults may continue to be active in the sedimentary basin, and their effect may be compounded by faults which owe their origin to gravity sliding within the sedimentary pile. The jointing or "cleat" in the high-rank coals is a consequence of the reduction in porosity and permeability brought about by the burial, compaction and continued diagenesis of the organic constituents of coal.

Post-depositional changes: Folding of coal seams has a profound effect on their minability. Steeper dipping strata may result in unfavourable overburden stripping ratios, and may lead to the cancellation of the project. Similarly, in the underground operations, if the dip of the coal seam is too steep, it can make further working of coal difficult, and in the case of longwall mining, extraction of coal may have to be given up. The heat associated with the intrusion of dykes and sills may some times have the beneficial effect of raising the rank of coal, but the intrusions may also cause problems in mining. The dykes and sills are generally doleritic. They are extremely hard, and by their baking effect, they render the surrounding area hard. Such intrusions are particularly common in the South African coalfields. They need to be carefully mapped, and their disposition has to be taken into account while planning the mining operations.

A common feature of the coal-bearing sequences is the presence of iron stone (siderite – $FeCO_3$) which is extremely hard. This creates problems in mining, because of the difficulty in separating coal and siderite. Iron sulphide (pyrite – FeS_2) may be precipitated along with coal as disseminations or as thin bands. This gives rise to the extremely troublesome acid mine drainage.

1.1.3 Importance of coal in the energy economy

Coal provides 25% of the global energy needs, and accounts for 40% of the world's electricity. Some countries are highly dependent upon coal for their electricity production: Poland – 93%; South Africa – 93%; Australia – 80%; China – 78%; Israel – 71%; Kazakhstan – 70%; India – 69%; USA (50%) (source: World Coal Institute, 2007 edition)

Coal is mined in all continents, except Antarctica. Proven Coal reserves in the world (909,064 million tonnes) are expected to last 147 years, while the oil and gas reserves have life times of 41 and 63 years respectively. Also, unlike coal whose occurrence is wide-spread, about two-thirds of oil and gas deposits in the world are confined to Middle East and Russia.

Countries with more than 0.1% of the global coal reserves are listed in Table 1.1.1.

It may be seen that just four countries, USA, Russia, China and India, account for about two-thirds of the coal reserves of the world.

The total global hard coal production in the world in 2006 was 5370 Mt (million tonnes), which is 8.8% higher than the figure for 2005. The total brown coal/lignite production in the world is 914 Mt, which is only marginally higher than the figure of 906 Mt in 2005. The top ten hard coal producers in the world and the production in Mt are as follows: China – 2842; USA – 990; India – 427; Australia – 309; South Africa – 244; Russia – 233; Indonesia – 169; Poland – 95; Kazakhstan – 92; Colombia – 64. Thus, China alone produces more than half of the coal production in the world. About 13% of hard coal (~717 Mt) is used in the iron and steel industry.

Table 1.1.1 Proved recoverable coal reserves at end-2006 (million tonnes).

Country	*Bituminous & anthracite (Mt)*	*Sub-bituminous & lignite (Mt)*	*Total (Mt)*	*Share (%)*
USA	111,338	135,305	246,643	27.1
Russia	49,088	107,922	157,010	17.3
China	62,200	52,300	114,500	12.6
India	90,085	2,360	92,445	10.2
Australia	38,600	39,900	78,500	8.6
S. Africa	48,750	0	48,750	5.4
Ukraine	16,274	17,879	34,153	3.8
Kazakhstan	28,151	3,128	31,279	3.4
Poland	14,000	0	14,000	1.5
Brazil	0	10,113	10,113	1.1
Germany	183	6,556	6,739	0.7
Colombia	6,230	381	6,611	0.7
Canada	3,471	3,107	6,578	0.7
Czech Rep	2,094	3,458	5,552	0.6
Indonesia	740	4,228	4,968	0.5
Turkey	278	3,908	4,186	0.5
Greece	0	3,900	3,900	0.4
Hungary	198	3,159	3,357	0.4
Pakistan	0	3,050	3,050	0.3
Bulgaria	4	2,183	2,187	0.2
Thailand	0	1,354	1,354	0.1
N. Korea	300	300	600	0.1
New Zealand	33	538	571	0.1
Spain	200	330	530	0.1
Zimbabwe	502	0	502	0.1
Romania	22	472	494	0.1
Venezuela	479	0	479	0.1
Total	478,771	430,293	909,064	100.0

Source: B.P. Statistical Review of World Energy Supplies, 2007.

Table 1.1.2 Top exporters of coal.

Country	*Total (Mt), of which*	*Steam*	*Coking*
Australia	232	111	121
Indonesia	129	104	25
Russia	92	82	10
South Africa	69	68	1
China	63	59	4
Colombia	60	60	0
USA	45	20	25

Source: World Coal Institute, 2007.

Table 1.1.3 Top importers of coal.

Country	*Total (in Mt), out of which*	*Steam*	*Coking*
Japan	178	105	73
South Korea	80	60	20
Taiwan	64	58	6
U.K.	51	44	7
Germany	41	33	8
India	41	22	19
China	38	29	9

Source: World Coal Institute, 2007.

Top exporters of coal are listed in Table 1.1.2.

1.2 CARBON EMISSIONS AND CLIMATE CHANGE

1.2.1 Carbon dioxide emissions and radiative forcing

Climate Change is any significant, long-term change in the "average "weather that a region experiences. The UN Human Development Report (2007) calls the Climate Change, "the defining human development issue of our generation". The World Health Organization estimated that the health impacts of climate change caused 150,000 additional deaths in 2003, and that the proportion of the world population affected by weather disasters doubled between 1975 and 2001. This is just an inkling of the disasters that are in store for humanity if we go on increasing the emission of greenhouse gases.

Fossil fuels (coal, oil and natural gas) account for 88% of the world's commercial primary energy. Burning of the fossil fuels leads to the production of climate-relevant emissions of carbon dioxide (CO_2), methane (CH_4), nitrogen oxides (NO_x), carbon monoxide (CO) and volatile organic compounds (VOC). The extent of emissions from various sources is as follows: (i) Energy industries – about 50%, out of which CO_2 accounts for 40%, (ii) Chemical products, particularly, CFCs – about 20%, (iii) Destruction of tropical rain forests and related causes – about 15%, (iv) Agriculture and others (e.g. waste deposit sites) – about 15%.

All greenhouse gases are expressed in CO_2 – equivalent terms, by adjusting for differences in radiative forcing.

The following conversion constants are quoted from "World Energy Outlook 2007", International Energy Agency, Paris, 2007, pp. 633–641.

General Conversion factors for Energy

To/From	*TJ* *Multiply by*	*Gcal*	*Mtoe*	*MBtu*	*GWh*
TJ	1	238.8	2.388×10^{-5}	947.8	0.2778
Gcal	4.1868×10^{-3}	1	10^{-7}	3.968	1.163×10^{-3}
Mtoe	4.1868×10^{4}	10^{7}	1	3.968×10^{7}	11630
MBtu	1.0551×10^{-3}	0.252	2.52×10^{-8}	1	2.931×10^{-4}
GWh	3.6	860	8.6×10^{-5}	3.412	1

TJ = Tera Joules; Gcal = Gigacalories; Mtoe = Million tonnes of oil equivalent; MBtu = Million British Thermal Units; GWh = Gigawatt hours.

1 million tonnes of oil equivalent = 1.9814 million tonnes of coal
= 0.0209 million barrels of oil/day
= 1.2117 billion cubic metres of gas.

Carbon is the principal constituent of all living matter, and all carbon is derived directly or indirectly from CO_2. Though CO_2 is present only in small quantities in the atmosphere (~0.03%), it has profound influence on the climate because it controls the amount of heat which is retained in the atmosphere. The mass of CO_2 in the atmosphere is estimated to be 2.2×10^{18} g. The burning of fossil fuels (coal, petroleum, and natural gas) releases about 1.5×10^{16} g of CO_2 per year. One-third of this (5×10^{15} g) is retained in the atmosphere, and the balance of two-thirds (about 1×10^{16} g) is taken up by the oceans and the biomass. Man's activities have already added 1.7×10^{17} g of CO_2 in the atmosphere (i.e. about 8% of the total mass of CO_2 in the atmosphere). If the entire mass of coal (7.6×10^{12} t) and oil (2×10^{12} t) are burnt, it would add 3.3×10^{18} g of CO_2 to the atmosphere. In other words, man is capable of raising the mass of CO_2 in the atmosphere by 150%. Atmospheric CO_2 is currently increasing at the rate of 0.5% per annum, and the airborne fraction of the emitted CO_2 is about 60%.

The CO_2 concentration in the atmosphere which was about 280 ppm at the time of the Industrial Revolution in 1850s went up steadily with the increasing consumption of fossil fuels. It is now more than 387 ppm today (highest in the last 650,000 years, and higher than about 40% since the industrial revolution). The annual mean rate of growth is 2.14 ppm in 2007 (as against the rise at the rate of 1.5 ppm during the period, 1970–2000). The Developed countries which have 15% of the world's population are responsible for 50% of the CO_2 emissions (Table 1.2.1).

The CO_2 emissions of the top five CO_2 emitters in 2005, 2015 and 2030 are given in Table 1.2.2.

Five countries (USA, China, Russia, Japan and India) currently account for 55% of global energy-related CO_2 emissions. The same countries will remain the top CO_2 emitters in 2030, but their relative ranks will change. China has overtaken USA in 2007, and will continue to remain the top emitter. India's rank will jump from fifth to third rank in 2015, and will remain so in 2030.

Table 1.2.1 Emission of greenhouse gases by some important countries.

Country	*CO_2 emissions (million tonnes)*	*Growth rate, 1990–2004*	*CO_2 emissions per Capita (tonnes)*
USA	6046	25	20.6
China	5007	109	3.8
Russia	1524	–23	10.6
India	1342	97	1.2
Japan	1257	17	9.9
Germany	808	–18	9.8
Canada	639	54	20.0
United Kingdom	587	1	9.8
Korea	465	93	9.7
Italy	450	15	7.8
World	28,993	28	4.5

Source: UN Human Development Report, 2007.

Table 1.2.2 Top five countries for energy-related CO_2 emissions in the reference scenario.

	2005		*2015*		*2030*	
	Gt	*Rank*	*Gt*	*Rank*	*Gt*	*Rank*
USA	5.8	1	6.4	2↓	6.9	2=
China	5.1	2	8.6	1↑	11.4	1=
Russia	1.5	3	1.8	4↓	2.0	4=
Japan	1.2	4	1.3	5↓	1.2	5=
India	1.1	5	1.8	3↑	3.3	3=

Gt = gigatonnes = 10^9 t.

Source: "World Energy Outlook 2007", p. 200.

Table 1.2.3 CO_2 concentrations and emissions.

1	*2*	*3*	*4*	*5*
350–400	445–490	2.0–2.4	2000–2015	–50 to –85
400–440	490–535	2.4–2.8	2000–2020	–30 to –60
440–485	535–590	2.8–3.2	2010–2030	+5 to –30
485–570	590–710	3.2–4.0	2020–2060	+10 to +60
570–660	710–855	4.0–4.9	2050–2080	+25 to +85
660–790	855–1130	4.9–6.1	2060–2090	+90 to +140

1 CO_2 concentrations (ppm).
2 CO_2 equivalent concentrations (ppm).
3 Global mean temperature increase above pre-industrial equilibrium (°C).
4 Peaking year for CO_2 emissions.
5 Global change in CO_2 emissions in 2050 (% of 2000 emissions).

Source: "World Energy Outlook 2007", p. 206.

The relationship between the increase in CO_2 concentrations (ppm) and the rise of global mean temperature above pre-industrial equilibrium (°C) is shown in Table 1.2.3.

1.2.2 Biophysical and socioeconomic consequences of Global Warming

It is expected that by about 2015, the CO_2 level will reach 400 ppm, with the concomitant rise of global warming by 2°C above the pre-industrial temperature. Limiting the global rise in temperature to 2°C provides a window of opportunity. The UN Human Development Report (2007) suggests a number of techno-socio-economic measures, such as carbon taxation, cap-and-trade programmes, reduction in emission quotas, encouraging renewable energy production through economic incentives, stringent implementation of efficiency measures in industry, building and transport sectors, support for breakthrough technologies of carbon capture and storage.

Global warming and sea level rise are going to have serious adverse consequences for agriculture, forests and ecosystems, water and the coastal zones in the country. The expected more frequent and intense heat waves are not only debilitating to humans, but are likely to spread malaria and dengue fever.

Between 2000 and 2004, 262 million people were affected by natural calamities attributable to climate change – of these 98% were in developing countries. A temperature increase of 3–4°C is projected to cause the displacement of 330 million people due to floods, malaria infection for 200–400 million people, extinction of 20–30% of all land species. In nature, life cycles of many wild plants and animals (for example, a wild flower and its pollinating insect) are seasonally synchronized. By affecting the temperature and precipitation, climate change may throw the seasonal synchronization out of gear, and thereby adversely affect the biodiversity.

The tipping point is 4°C. If the global warming goes beyond 4°C, the earth would face a catastrophe – the Amazon Rain forest may become a desert, and the sea level may rise by 80 ft. If the earth is to be saved from such an environmental catastrophe, the Developed countries need to cut their greenhouse gas emissions by 80% by the year 2050, with 20–30% cuts by the year 2030.

IPCC came up with an ambitious scenario of stabilizing the CO_2 emissions in the 445–490 ppm CO_2 – equivalent, with energy-related CO_2 emissions reduced to 23 Gt in 2030.

The figure of 23 Gt is about 19 Gt less than the Reference Scenario (in which the government policies are assumed to remain unchanged since mid-2007), and about 11 Gt less than the Alternative policy scenario (which takes into account the adoption of policies and measures that the governments around the world are contemplating).

In the IPCC-favoured scenario, global energy-related CO_2 emissions peak at 2012 around 30 Gt, and then decline to 23 Gt in 2030, apart from 6 Gt of CO_2 from non-energy related sources, such as, land-use changes and forestry. The figure of 23 Gt is 13% lower than the emission figure for 2005. The International Energy Agency, Paris, (2007) came up with a pathway to achieve this goal (Table 1.2.4).

The following steps need to be taken to achieve the IPCC goal: (i) Improved efficiency in fossil fuel use in industry and buildings (savings of more than 25%, relative to the Reference Scenario) (ii) Lower electricity demand through more efficient electricity use in buildings (savings of about 13%), (iii) Switching to second

Table 1.2.4 World energy demand in the 450 stabilisation case (Mtoe).

	2005	*2015*	*2030*	*2005:2030**
Coal	2,892	3,213	2,559	–0.5
Oil	4,000	4,278	4,114	0.1
Gas	2,354	2,736	2,644	0.5
Nuclear	721	1,037	1,709	3.5
Hydro	251	393	568	3.3
Biomass	1,149	1,484	1,966	2.2
Other renewables	61	223	471	8.5
Total	11,429	13,364	14,031	0.8

* Average annual rate of growth.

Source: "World Energy Outlook 2007", p. 209.

generation in biofuels in transport (savings of 4%), (iv) Enhanced use of renewables in the power sector (savings of 19%), (v) Increased use of nuclear power (savings of 16%), and (vi) CO_2 capture and storage (CCS) (savings of 21%). It should be emphasized that these steps are not going to be easy. Nuclear power faces many policy and regulatory hurdles, and the techno-economic viability of CCS is yet to be established. Evidently, governments all over the world have to work promptly and vigorously to make the huge investments needed for the purpose. Any delay will make it progressively more difficult to achieve the target.

1.3 COAL MINING TECHNOLOGIES AND THE ENVIRONMENT

The environmental impacts of different methods of coal mining is based on the following considerations: (i) The annual production of coal in the world (~5370 Mt in 2006) is higher than any other metallic and non-metallic mineral, (ii) Its use is widespread because of its versatility as a fuel and industrial raw material, (iii) It is mined both by opencast and underground mining, or combinations of both, (iv) Transport of coal is expensive. Hence, industries using large quantities of coal, such as, thermal power stations, iron and steel complexes, etc. tend to be located near the coalmines. Consequently, coal-mining areas tend to be the foci of a wide range of environmental stresses, arising not only from the coal mining industry itself, but also from coal-using industries, (v) Coal has a variable composition (e.g. rank of coal, calorific value, sulphur content) depending upon its geologic setting and burial history. It may have to be preprocessed (e.g. washed), depending upon the requirements of the user. Depending upon the composition of coal (such as sulphur content), mining of coal may have consequences such as acid mine drainage (AMD) and burning of coal could cause acid rain, (vi) The environmental impacts associated with the coal cycle are complex and interactive. They may be instantaneous (e.g. land clearance), accumulative (e.g. spoil deposition), or progressive (pneumoconiosis).

The following account is largely drawn from Chadwick et al. (1987). The special feature of this excellent work is its particular reference to the mining problems of the developing countries.

1.3.1 Opencast mining

The following are the advantages of the opencast mining (Chadwick et al., 1987, pp. 100–101): (i) high productivity per man-hour, and high output per mine, (ii) low annual capital costs and operating expenses per tonne of mineral mined, (iii) easy to manage the equipment and the workforce, (iv) further exploration can be carried out relatively cheaply, and would yield data of greater confidence, (v) allows the use of large-capacity machines, (vi) better safety record (relative to underground mines), (vii) labour prefers the opencast mines, relative to underground mines, (viii) few problems with seam gases, heat and roof collapse, and subsidence, (ix) shorter lead time, relative to underground mining.

Because of these advantages, opencast mining is the most prevalent form of mining, accounting for 60% of the large mines (i.e. those with production of more than one Mt/y), and 69% of the production.

Sengupta (1993) gave a detailed account of dragline operations to undertake surface coal mining coupled with reclamation. The dragline initially cuts a trench called as keycut, adjacent to the newly formed highwall. The length of the block is the distance between the previous keycut position and the present keycut position. The keycut material is dumped in the bottom of the mined-out pit. The operating cycle of the dragline consists of five steps: (i) The empty bucket is placed in a position ready to be filled, (ii) the bucket is dragged towards the dragline in order to get filled, (iii) the filled bucket is hoisted up, and the boom is swung towards the spoil pile, (iv) the bucket dumps the spoil material it is carrying, (v) the bucket is lowered, and the boom swings back to the cut.

The width of the panel is an important consideration in the dragline operations. It is chosen on the basis of the following considerations: (i) coal loadout (the practical minimum width is 28 m; any width less than 28 m hampers maneuverability of the coal trucks), (ii) slope stability: wide pits are safer for mine and equipment, (iii) cycle time: depends upon the swing of the dragline; for medium and large draglines, wide panels give better productivity, (iv) spoil regrading: the wider the panel, the greater would be the amount of dozing to be done to level the spoil piles, (v) walking: the wider the panel, the less would be the walking needed for the dragline, (vi) spoiling at entryways: the narrower the panel is, the shorter would be the spoiling radius.

The cycle time for a small dragline increases significantly if the panel width is increased, but if large draglines are used on the same depth of overburden, the increase in the cycle time will only be marginal. For instance, when a large dragline is used, the cycle time increases by only 1.6% even though the panel width has been increased from 75 ft. (22.8 m) to 175 ft. (53.3 m) (Sengupta, 1993, p. 39).

1.3.1.1 Mine layouts

When coal measures are in the form of flat, tabular deposits, they can be conveniently mined by strip or area mining (Chadwick et al., 1987, p. 111). Excavation is started in the area at or close to the surface where the thickness of overburden is at a minimum.

The overburden is first removed in order to expose the first strip of coal, and this overburden is deposited outside the proposed pit area. After coal is removed from the first strip, a second strip of overburden is then excavated along the downdip side of the first. "The material taken from this cut is cast directly into the void created by the first strip" (Chadwick et al., 1987, p. 110). This process of stripping is continued, until the overburden to be excavated is found to be too thick to be stripped economically or when the excavation has reached its maximum depth or when some other boundary condition is reached.

Contour mining which is a variant of strip mining is used to mine flat or gently dipping coal seams exposed on steeply sloping hillsides (Chadwick et al., 1987, p. 111). "Overburden is removed from above the seam outcrop and placed below the exposed coal on the downhill side" (Chadwick et al., 1987, p. 112). Successive cuts are made on the hillside until a situation arises whereby the high-wall height is such that further excavation is no longer economic. The excavation process leaves behind a long, narrow bench which follows the contours of the hillside.

Open pit mining is best suited to excavate coal measures which are large, thick, and irregular, or which are multi-seam and steeply dipping. If a seam is too thick to be mined from a single face either because of the limitations of the reach of the mining equipment or because of the possibility of slope failure, recourse is taken to the development of several smaller faces. Similar conditions hold good for multi-seam measures – faces or benches may be developed for individual seams in such a manner that some faces are used for the removal of overburden and interburden, and some for winning coal. Chadwick et al. (1987, p. 113) describe a possible layout of a open-pit mine. In this arrangement, the excavated overburden is deposited outside the pit, until a suitable area becomes available within the pit area itself. Only when the excavation is started on the lowest bench, will it become possible to emplace the overburden material to fill the previously created voids.

A variety of machines are used in opencast mining. It is convenient to use scrapers to remove the top soil, subsoil and unconsolidated overburden. Though stripping shovels and bucket wheel excavator with boom stacker are used in strip mining, the walking dragline is the most widely used equipment for strip mining of regular, flat coal deposits. It strips the overburden and casts it directly into the void. In some situations, such as when the overburden strata are composed of resilient material, it may be necessary to drill the strata, and then break it up with explosives. Coal is won in a second drilling and blasting operation. Coal is loaded out either by power shovel or front-end loader into trucks for being hauled away. Where the ground is sufficiently hard, combination of power shovels, hydraulic excavators and front-end loaders are commonly used to remove both the overburden and coal from multi-bench systems. Where the ground is soft, the usual practice is to use combinations of bucket wheel and bucket chain excavators with railcar or conveyor belts.

Figure 1.3.1 (source: Chadwick et al., 1987, p. 159) shows how opencast coal mining with progressive restoration can be carried out using a dragline. A bird's eye of opencast mining and progressive restoration using a dragline is given in Figure 1.3.2 (source: Chadwick et al., 1987, p. 160).

In some open pit mines in Indonesia, mining operations have been abandoned in the past when they developed long high walls. Matsui et al. (2001) developed a high wall mining system to extract coal from exposed seams at the base of the open cut or stripping operations. The equipment used in high wall mining is analogous to the

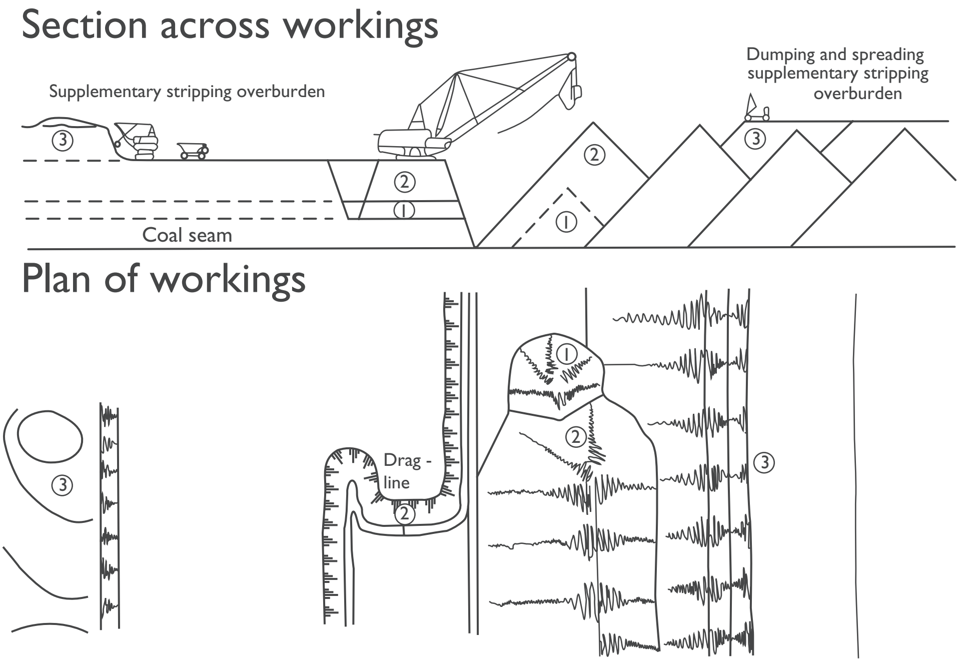

Figure 1.3.1 Opencast mining with dragline with progressive restoration. 1. Carbonaceous sediment, 2. Overburden, 3. Topsoil.

Source: Chadwick et al. 1987, p. 159.

machinery used in underground mining. Figure 1.3.3 (source: Matsui et al., 2001) shows how the high wall mining is carried out with the Addcar system. After making a small bench, mining can be started from the outcrop with minimum environmental disturbance. As only a narrow bench is required to gain access to the coal seam, there is minimal disturbance to the surrounding land, and there is no need to worry about failures of waste rock spoils.

1.3.1.2 Projected advances

The following are the projected advances in open-pit mining (Hustrulid, 2000):

1 Increase in mining geometry, steeper slopes, deeper pits,
2 New, large production machines/techniques

    2.1 400_+ t capacity trucks, 76.5 m^3 shovels and 381 to 432 mm drill holes
    2.2 Continuously variable explosives with respect to energy and other Properties,
    2.3 Electronic blasting caps

3 Mechanisation/automation

    3.1 Very high accuracy GPS on all machines
    3.2 Driverless trucks

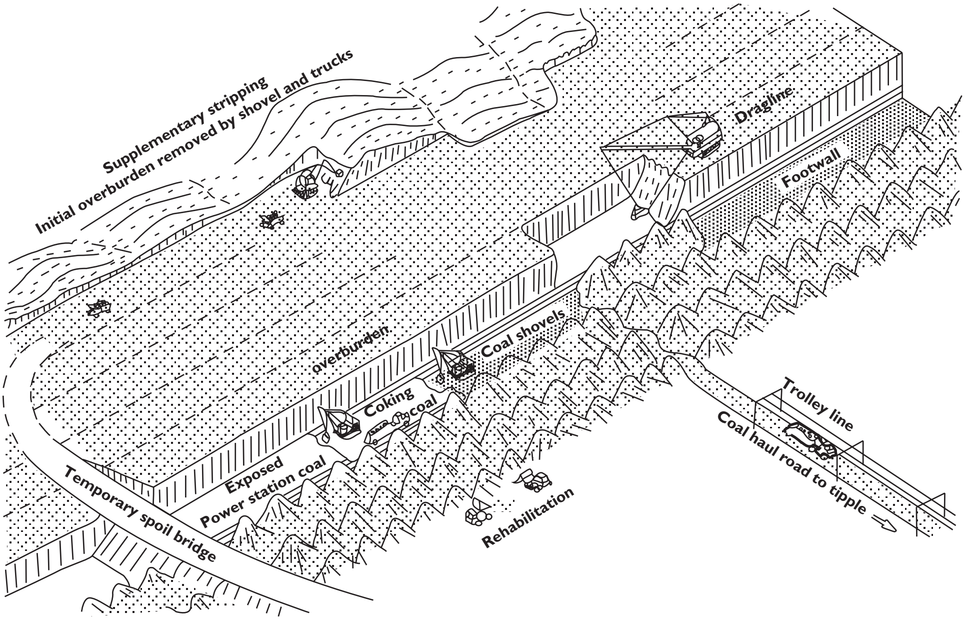

Figure 1.3.2 A bird's eye view of the opencast coal mining and progressive restoration, using a dragline.

Source: Chadwick et al. 1987, p. 160.

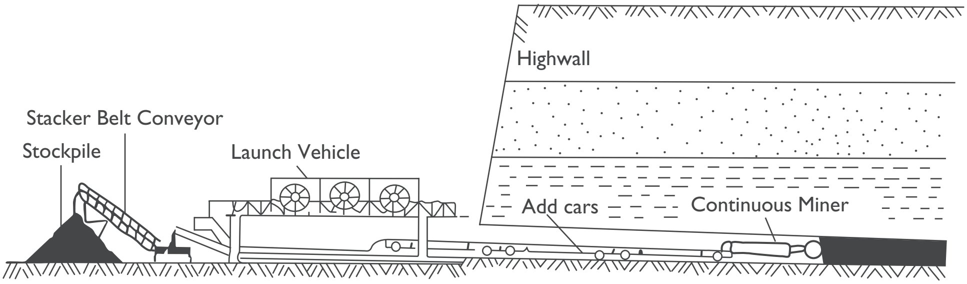

Figure 1.3.3 High wall mining using the Addcar system.

Source: Matsui et al. 2001, p. 488.

  3.3 Remotely-operated drills
  3.4 Remotely-operated shovels

4 MARC in place, guaranteed availability. Advanced condition monitoring and Prediction
5 Few working places, with high utilization
6 Short time between stripping and production
7 Automatic sampling of drill cuttings, remote after blast sampling
8 Automatic sampling in the dipper/truck bed or along the route. Automatic destination assignment
9 Simulation is extensively used to plan production.

The projected advances in open-pit mining are realisable only in the context of the following considerations (Hustrulid, 2000): (i) The very large automated machines and techniques require precision cutting of bench faces and maintenance of bench widths, (ii) The production would be coming from a limited number of working places, and the plant should be able to handle the feeds in such a situation, (iii) It may be necessary to maintain several stockpiles, and rehandle the ROM, (iv) A great number of safety factors may have to be considered, to take care of the mixture of automated and non-automated jobs.

Presently, even the least expensive underground mining method (say, by panel caving) costs 3 to 5 times more per tonne than the material handled by the open pits (Hustrulid, 2000).

1.3.2 Underground mining

1.3.2.1 Advantages

The following are the advantages of the underground mining (which can also be thought of as the disadvantages of the opencast mining): (i) mining can be carried on round-the-year, and round-the-clock, unaffected by weather conditions, (ii) minimal environmental disturbance of the surface, (iii) relatively small amount of spoil is generated, with the implication that less land is disfigured and contaminated, and the expense of rehabilitation of the mined land is correspondingly limited, (iv) oxidation problems at the outcrop are less likely, (v) mining can be done selectively – specific sections of seams can be mined to maintain quality, and to relieve breakdowns, (vi) the working environment can be adjusted, etc.

An underground mine may be a drift mine or slope mine or vertical shaft mine, depending upon the inclination of the access to the seam. The choice is determined by the position of the seam relative to the surface and the economics of mining. Where a seam outcrops at the surface and is more or less horizontal, it can be conveniently mined as a drift mine (Chadwick et al., 1987, p. 115). Access by inclined tunnel is limited to seams which occur at shallow depths. This is so because the length of the tunnel tends to be about four times that of the vertical depth of the seam (Chadwick et al., 1987, p. 115). A vertical shaft mine is necessary to mine deep seams. For purposes of ventilation, and to provide means of egress, all underground mines should necessarily have at least two accesses from the surface. For this reason, most mines contain vertical shafts and inclined tunnels.

Table 1.3.1 gives a comparison of the engineering aspects of shaft and drift types of mines.

Other considerations affecting the choice between shat and drift are: construction time, extra distance of drift, geological factors, weak/wet strata, and the nature of the reserves.

In the past, tunnels were constructed through a cycle of drilling, blasting, loading and haulage of the broken rock and installation of supports. The current practice is to use tunnel boring machines with multiple cutting heads to drive the tunnels continuously, without using explosives. The shafts are usually circular in outline, and are lined with concrete. Just as happened in the case of tunnels, shafts are now-a-days sunk using large diameter shaft boring machines, thereby avoiding blasting. Chadwick et al. (1987, p. 118) gives a schematic diagram of a vertical shaft mine.

Table 1.3.1 A comparison of the engineering aspects of shaft and drift mines.

	Shaft	*Drift*
Mineral	a Limited to between 2.2 and 4.4 M tonnes/annum/shaft. b Intermittent feed to coal Preparation plant evened out by surface bunkers or stockpiles. c Adequate pit bottom bunkerage essential. d Inspection and maintenance carried out from the winding System.	a No significant limit on capacity; upto 12 M tonnes/annum is achievable. b Continuous feed to coal preparation Plant but stockpiles are still required to even out peaks and cover breakdowns. c Drift bottom bunker desirable for smooth flow and to cover belt stoppages. d Haulage system required for men and materials access for conveyor and drift inspection and maintenance.
Labour	a High capacity and shortest time between surface and pit bottom. b Capacity of second egress at mineral shaft limited to around 30%/40% of man shaft.	a Capacity similar to shaft but time between pit top and seam level is greater. b Maintenance haulage in conveyor drift may only give limited second egress facility but conveyor could be equipped for man-riding if speeds are appropriate, or men could walk out on a power failure.
Material	a Large equipment can be accommodated but this cannot always be fully utilized due to restrictions of underground roadways. b Speedier transport of materials to pit bottom.	a Equipment size limited by drift dimensions but this will be commensurate with underground roadways. b Slower transport of materials to drift bottom but problems of transfer to underground haulage systems may be less.
Ventilation	Resistance is relatively less.	Resistance is relatively more.
Services	Allows a better arrangement of electric and other cables, water and compressed air pipes.	Arrangement of electric and other cables, water and compressed pipes, is relatively less convenient.

Source: Chadwick et al. 1987, p. 116 & 117.

The design of a major access underground has to take into account the geotechnical and hydrological characteristics of the rock strata through which the entry structure is to be driven. A weak or unconsolidated ground may lead to roof collapse, and large quantities of groundwater may flood the mine. Dewatering at shallow depths can no doubt be accomplished by pumping, but this may not always be possible in the case of deep strata. Grouting with cement or chemical solutions to fill the voids in the rock mass is the only remedy in such a situation – grouting not only reduces the permeability of the rock mass, but also increases its strength. An alternative is freezing the water in the voids of the rock mass, by the circulation of the coolants. This has the same effect as grouting, but this technique is seldom used in the developing countries.

1.3.2.2 Room-and-pillar method and longwall mining

The room-and-pillar method and longwall mining are the two common methods of mining coal. The room-and-pillar method is best suited to mine relatively thick coal seams which occur at shallow depths, and have reasonably strong roof and floor strata. In the first stage, a series of intersecting openings are driven through the seam. At this point, solid pillars of coal support the roof. The size of the pillars needed depends upon the depth of the seam – at shallow depth, small pillars would suffice, but greater depths, the pillars have to be thick. Thus, in the first stage, the percentage of recovery of coal decreases with increasing depth. In the second stage, the pillars are mined, allowing the roof to collapse into the abandoned area.

UNEP Tech. Rept. No. 5 (1991, pp. 11 & 12) describes in detail an open stope with regular pillars, the sub-level stoping longitudinal slopes in narrow veins, and the process of cut-and-fill mining operation.

In the past, the cycle of winning coal used to be through drilling and blasting the seam, loading the coal and hauling it to the surface. The present practice in most mines is to mine coal continuously with a cutting head, and load the coal to a shuttle car or an extensible conveyor system. Such a system has a much higher productivity than the conventional cycle.

Longwall mining is characterized by a greater flexibility. It is the preferred method for mining deep, thin seams, where the dips are steep, and the roof strata are weak. This method involves mining coal along a single face about 100–200 m long, using a rotary trim shearer, a trepanner or a coal plough which traverses along the face. The broken coal is loaded onto a series of conveyor systems. The working area is protected by self-advancing, hydraulic roof supports. As the working face advances, the roof supports move synchronously. As should be expected, the removal of the roof supports will result in the collapse of the roof in the area from where coal has earlier been removed.

There are two basic variations of longwall mining – longwall advance where the face is moved into the seam away from the entry area, or longwall retreat, where the face is opened up at the boundary of the seam, and worked backwards towards the original entry point. Chadwick et al. (1987, p. 123) gives a schematic diagram of longwall retreat mining.

The principal advantages and disadvantages of the longwall mining vis-à-vis room-and-pillar method are summarized as follows (source: Chadwick et al., 1987, p. 124).

Advantages

(1) Higher overall recovery of *in situ* coal reserves, (2) Lower cost of timber supports, roof bolts, etc., (3) Greater productivity since fewer personnel are needed for equivalent coal production, (4) Improved efficiency in ventilation as an extensive system of "first workings" is not needed, (5) Can cope with weak strata and with mining at great depths, (6) Better protection for operating personnel at the working face.

Disadvantages

(1) The equipment needed for the purpose is expensive, and needs a large capital outlay, (2) Since the working mine faces are large and few in number, the stoppage of work at a single face may mean a large drop in the total mine output, (3) Large haulage capacity is needed over a single line to transport coal from the mine face to

the top, (4) Cannot cope efficiently with thick seams, or geological irregularities in the seam, (5) Will always produce subsidence at the ground surface.

Irrespective of the method of mining used, a mine should have good ventilation. The purpose of the ventilation in a mine is not only to provide fresh air to the work force, but also to cool the work face and remove dust and noxious gases. Ventilation is generally provided by powerful fans (pressures upto 6 kpa) located at the surface. Fresh air is circulated through the mine from one entry, and the exhaust is removed through another entry.

Surface subsidence invariably accompanies longwall mining. Similarly, surface subsidence can be expected to take place when most or all the pillars in the room-and-pillar method are moved. Surface subsidence can, however, be minimized by sand stowing under pressure or back filling with gangue material or the new technique of emplacement of paste. Tailings are being increasingly used for mine backfill or surface stackings. This would require very high solids content. Previously, tailings dams have been used for water recovery and solids disposal. Paste thickeners have long been used by the alumina industry and the thickener technology is being applied to mineral industry as a whole. Deep cone thickeners are used to produce pastes with over 70% solids, suitable for backfill and stacking.

1.3.2.3 Special problems of underground mining of coal

The underground mining of coal has some special problems of critical importance:

i Seam gas: Coal measures may have large contents of methane (also called "fire damp"). Historically, methane explosions have caused several of the worst mining disasters in the world. The methane hazard can be minimized by the appropriate design of the workings and equipment, sufficient ventilation and drainage of methane gas. Continuous monitoring of the gas emissions is necessary to alert the workers before the gas concentrations reach dangerous levels. On the basis of *in situ* gas pressure, flow rate (in terms of m^3 per tonne of ROM coal), and the chemical composition of coal, it is possible to predict the likelihood of gas emissions, and incorporate this aspect in the mine design.

ii Cleat of coal: Cleat refers to the fractures in the coal seam. The existence of cleats in a seam can assist in the winning of coal in the course of longwall mining. Cleats have a bearing on porosity and permeability. Consequently, underground openings driven parallel to the orientation of cleats, may be characterized by higher rates of water and gas seepage.

iii Roof and floor of the seam: If the roof of a seam is composed of thick strata of strong, well-cemented, unfissured sandstone, it may not cave. This is an important consideration in longwall mining.

iv Liability of coal for spontaneous combustion: In the presence of air, coal may get oxidized, releasing energy. If the air flow is sufficient to oxidize coal, but not sufficient to remove the heat generated, spontaneous combustion takes place. Spontaneous combustion may occur underground, or on the surface (such as stockpiles, storage bins or spoil tips). It can be prevented by isolating the broken coal from air flow or by compaction. The tendency of given coal for spontaneous combustion could be assessed from the degradability of coal, and rank of coal.

v Swell factors: A unit mass of coal will occupy a greater space after excavation. The density of mined coal will hence be lower than the same coal *in situ*. This factor has to be taken into consideration in the transportation and storage of coal, and in backfilling the excavations.

1.3.3 Equipment automation

Though mobile mining equipment represents only a small portion (about 10%) of the costs of a mining project, the mine's performance and profitability are critically dependent upon the choice of the mobile equipment technology. In order to get the best out of the automated mobile equipment, it needs to have trained personnel, supportive infrastructure, monitoring and information transfer systems, established working procedures, etc.

Puhakka (2000) gave an account of the OPTIMINE simulation tool for the selection of mobile fleet. The tool combines the performance capabilities of the machines with operational knowhow and the mine environment, to optimize the performance of the mobile fleet, scheduling of work, and fine-tuning the layout of the mine. OPTIMINE can be used to identify the effect of a particular change (say, one additional turn in a continuous loading cycle) to the daily capacity. Pukkila and Sărkkā (2000) developed the software for Intelligent Mine. This includes the mine-wide information and data acquisition system, high-speed two-directional mine-wide communication network for monitoring and control, mine planning, automated, and tele-operated machinery connected to the information network, etc. The lessons learned through the use of Intelligent Mine software have been used in Outokumpu's Kemi chrome mine in Finland. Kay (2000) explains how the digital blasting technology developed by Orica can revolutionize mass mining. The new technology allows large and complex blasts to be fired routinely and with minimum of risk.

1.3.4 Environmental impact analysis of coal mining

The main environmental consequences of the mining projects are shown in Figure 1.3.4 (source: UNEP Tech. Rept. No. 5, 1991, p. 84).

An Environmental impact may be defined as a change in the environmental parameters, over a specified period, and in a specified geographical area, resulting from a particular activity compared to the situation which would have existed had the activity not been activated.

Environmental Impact Analysis (EIA) may be described as a process for identifying the likely consequences for the biophysical environment and for man's health and welfare while implementing particular activities, and to convey this information to the decision makers (Wathern, 1989, p. 6). In almost all countries, EIA is obligatory for the whole range of industries covering mining, treatment, transportation, processing, etc. of ores.

EIA may be considered as a data management process, with three components: (1) Identification and if possible, collection of appropriate information necessary for a particular decision to be taken, (2) Projection of changes in environmental parameters arising from the implementation of the project, compared with the situation that could exist without the proposal, (3) Recording and analysis of actual change (Wathern, 1988, p. 17). Nijkamp (1980) proposed a framework for integrating the environmental analysis with economic and social issues.

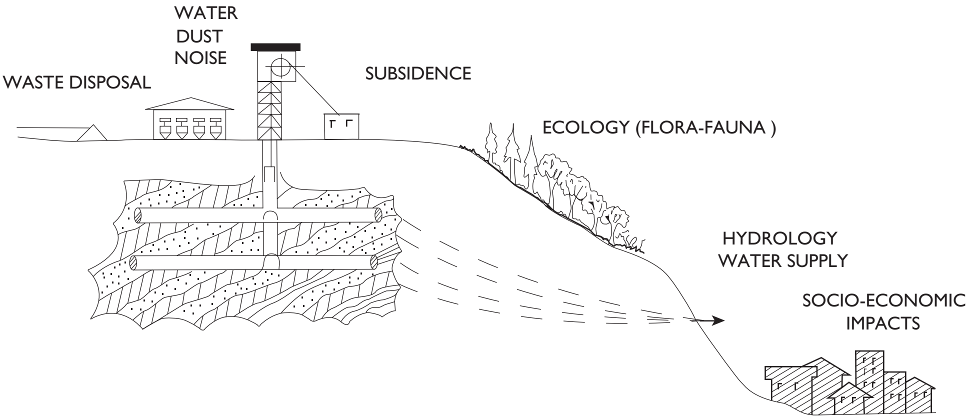

Figure 1.3.4 Main environmental consequences of the mining projects.

Source: UNEP Tech. Rept. No. 5, 1991, p. 84.

The procedure for Environmental Impact Assessment in the coal mining industry is shown in Figure 1.3.5 (source: Chadwick et al., 1987, p. 150).

The environmental effects of mining, such as the release of the pollutants, degradation of the landscape, disturbance in the habitat, etc. are inter-related. Consequently, change in one particular environmental component (e.g., process technology) will often cause direct and indirect changes in other components (e.g. tailings disposal). So it is necessary adopt a holistic approach in the EIA process.

"EIA is a dynamic process of examination, review and reformulation of project options until a consistent view emerges as the likely impact of the various options" (UNEP Tech. Rept. No. 5, 1991, p. 78). Four key steps are involved in this cyclic process: (i) Identification of the kind of consequences that the project could lead to, (ii) Prediction of the extent of changes in the environmental parameters that could arise from the project, (iii) Evaluation of the significance of the changes, and (iv) Mitigation of the environmental impact.

EIA documents are usually prepared by multi-disciplinary teams. The personnel involved should have both environmental expertise, as well as technical knowledge of the project itself. They should evaluate various techno-socio-economic options, and come up with their recommendation for the most practicable option. The EIA for a mining project should include a detailed description of the project, projected development of the area and sites for waste disposal. Particular attention should be paid to the location and design of the tailings ponds to take care of potential overflows and runoff of rainwater. Remedial measures, such as control of AMD, rehabilitation of the mined land, and mine closure, should be planned for, and integrated into the mine plan.

1.3.5 Rehabilitation of mined land

Though mining companies are required by law to submit plans and commit funds for the rehabilitation of the mined land when once the mine is closed, enforcement has not always been strict enough. It is particularly difficult in the case of small mines.

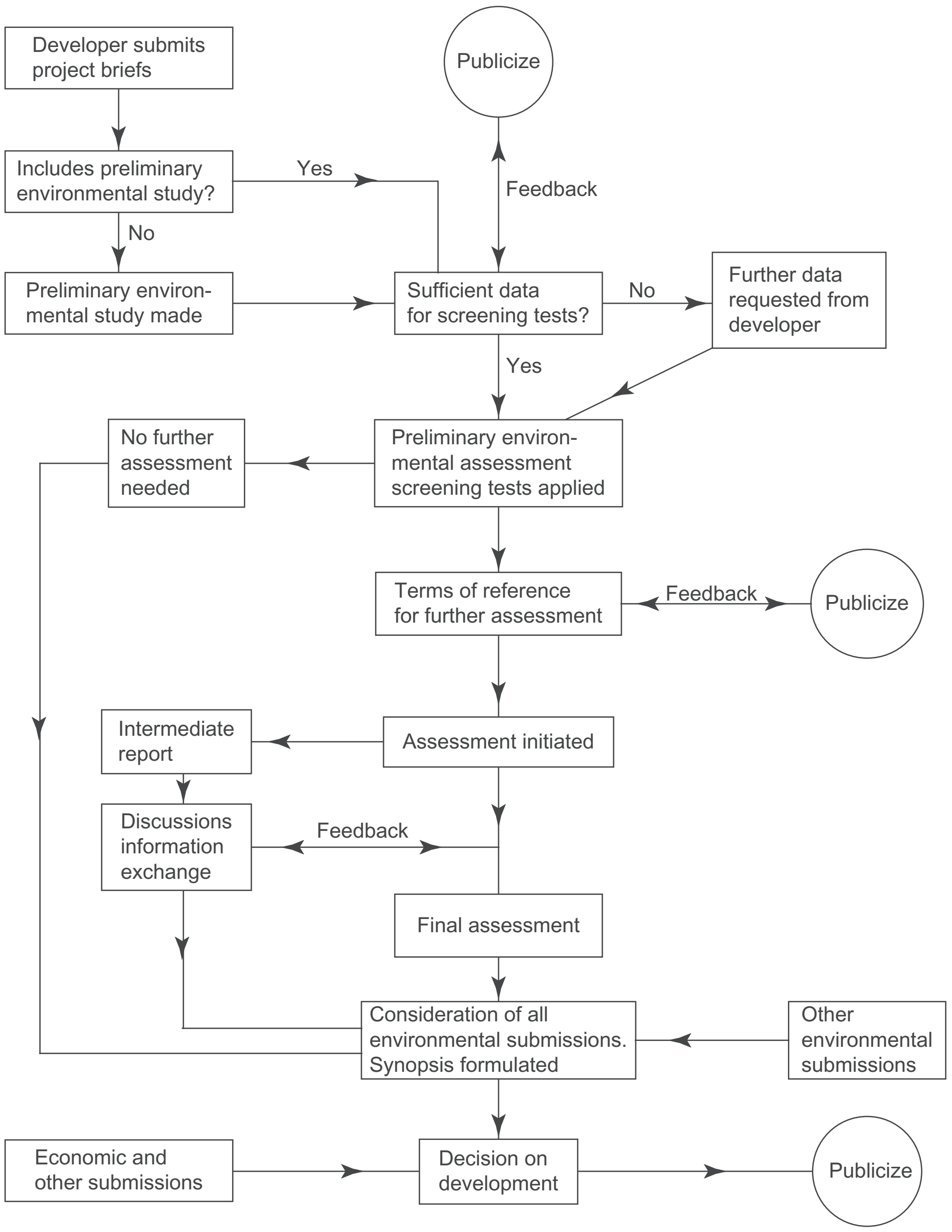

Figure 1.3.5 Procedure for EIA in the coal mining industry.

Source: Chadwick et al. 1987, p. 150.

Chadwick et al. (1987, p. 203) gave an account of the steps involved in the restoration of mined land.

Though the climate, soil and hydrological and methods of mining vary greatly in different areas, there are some common elements in the techniques of rehabilitation:

i Removal and retention of top soil, to be respread in the area that is being rehabilitated,
ii Reshaping the degraded areas and waste dumps in such a manner that they are stable, well drained, and suitably landscaped for the desired long-term use,
iii Minimizing the potentiality for wind and water erosion,
iv Deep ripping of the compacted surface,
v Revegetating with appropriate plant species in order to control erosion, and facilitate the development of a stable ecosystem compatible with the projected long-term use.

Amelioration methods can be custom-made for a given situation, as follows (Chadwick et al., 1987).

Low pH (usually <5): Amelioration by liming. Acid-tolerant species may be planted;
High pH (usually >8): Salt content may be removed by leaching. Salt/alkali-tolerant plants may be grown;
Low nutrient status: Nitrogen deficiency may be ameliorated by nitrogenous fertilization or by growing legumes;
Low moisture levels: Ridging, furrowing and mulching, and growing drought-tolerant plants;
Soil amendment: use of other wastes, such as fly ash, slag, etc.;
Construction of artificial wetlands for treatment of acid mine drainage and polluted runoff.

Experience has shown that purely civil engineering techniques, such as terracing and cementing, do not work, as mining wastes may be inhospitable and often toxic. Rehabilitation through vegetation has a number of benefits, particularly with regard to the developing countries in the tropics: (i) it is environment friendly and cost effective; (ii) it needs no costly or imported inputs or technology; (iii) it can generate employment of unskilled people, particularly women; and (iv) site beautification can also be accomplished in the process.

Mining disfigures the landscape besides causing landslides, subsidence, pollution of water and soil, and lowering of groundwater. Explosions can cause much damage. Restoration of mined land involves landscaping and revegetating of spoil heaps, pits, disused industrial areas and other kinds of dereliction caused by the mining activities (Chadwick et al., 1987, p. 173). In general, restoration is aimed at restoring the productive features of the landuse, improving the aesthetic features of the landscape, and reducing the possibility of further environmental degradation. The mechanics of restoration would depend upon not only on the nature of the substrate, but also on the intended purpose of restoration, such as, building an industrial estate, arable use, pasture, woodland, etc.

It may not be possible, and sometimes it may not be even desirable, to restore the landscape, vegetation and land use to the exact condition that obtained prior to mining. Often the restoration modality will be determined by the economics of the operations (expenditure on restoration as against the expected income from the new vegetation), social priorities, and the government regulations. It may turn out that the proposed restoration of the mined land may result in a better landuse than before.

The following factors have to be taken into account in determining the restoration procedure:

Climatic factors: Restoration in areas of dry or humid tropics is generally more difficult than in temperate climates. This is so because the evapotranspiration is high in tropical areas, and the rainfall is often unpredictable and uneven – for instance, half of the annual rainfall may get precipitated in a matter of hours. This would lead to flash floods and severe erosion in unvegetated areas.

Nature of the substrate: In the humid tropics, the soils tend to be leached, poor in nutrients and organic matter, and iron pans may develop in the soil structure. Subsurface soil may sometimes be richer in nutrients, and this factor should be kept in mind in the process of restoration.

Vegetation: Choice of plants to be used in revegetation needs a detailed knowledge of the needs for the establishment and maintenance requirements of the plants, but such knowledge is not available for non-crop tropical plants. Vegetation chosen should be able to survive in nutrient-poor, acid and toxic conditions.

Social and economic factors: Social and economic factors are of crucial importance. If the society prefers to restore the mined land as woodland, the kind of trees that need to be planted (fruit trees, timber trees, leguminous trees, etc.) and the economics (investment versus the returns) have to be carefully chosen. If the society favours the use of the restored land as a pasture, decision has to be chosen about the kinds of grasses that need to be planted, and the kind of animals that would be allowed to graze. In the Indian context, the mining companies simply plant lots of acacia trees in order to satisfy the government regulations about reclamation of mined land.

If right from the outset, the mining company makes a projection of how much spoil, of what characteristics is likely to be produced, and maintains records where the spoils have been tipped, it would greatly aid in planning the restoration.

1.3.6 Economics of environmental protection

In the context of the increasing public consciousness about environmental consequences of any commercial activity, it is no longer possible to take decisions about mining based on commercial rationale alone. A community may wonder whether the economic benefit from a mine is worth the ugly scar that would be left behind when the mine is closed. Previously, mining companies used their public relations exercise to *sell* a project. Now they use community consultation techniques to *develop* the project in harmony with the stakeholders who will be affected by the mine.

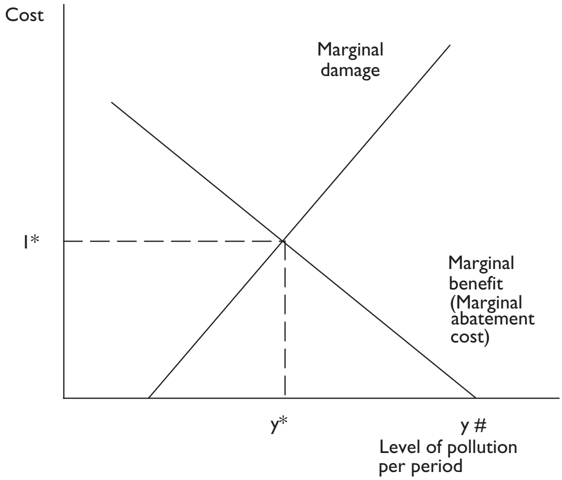

Figure 1.3.6 Economics of environmental protection in mining.

Source: Maxwell and Govindarajulu, 1999, p. 13.

Maxwell and Govindarajulu (1999, pp. 7–17) gave a good analysis of the economics of environmental protection in mining, with particular reference to Australia. It has been estimated that mining companies in Australia spend upto 5% of capital and 5% of operating costs for new mining projects to maintain best practice environmental management.

Environment has been attracting considerable interest from the economics. It is generally held that markets do not allocate environmental resources efficiently. This is so because many environmental resources are public goods. There is obviously a need for environmental protection regulation. The point that Maxwell and Govindarajulu (1999) raise is how zealous that such a legislation should be. If it is too demanding, the mining operation would result in less than the optimal level of output. The diagram of Coase helps us to understand the economics of the environmental impacts of a mine in terms of curves for marginal damage to the environment (air, water, soil, noise, etc. pollution and aesthetic damage) versus marginal abatement cost (or marginal benefit). The most economically efficient level of environmental damage occurs where the marginal damage and the marginal benefit curves intersect (Figure 1.3.6).

1.4 ENVIRONMENTAL IMPACT OF THE COAL CYCLE

1.4.1 General considerations

The major environmental and health impacts of the coal cycle (mining, preparation and beneficiation, transport and usage and utilization) are summarized in Table 1.4.1 (Chadwick et al., 1987, pp. 135–136).

The environmental impact of coal industry arises from the preparation, transportation; washing and combustion of coal, etc. (see Das & Chatterjee, 1988, for a good summary of the topic).

Table 1.4.1 Major environmental and health impacts of coal cycle.

Operation	*Environmental impact*	*Health impact*
Surface mining: Many variations (contour stripping, mountain top area mining, open pit), and machinery-use options (shovel-truck, dragline, continuous mine). All basically involve removal of vegetation, top soil and overburden to expose coal. Usual depth limit ~300 m.	Destruction and disruption of vegetation, natural drainage patterns and land use in the area of the mine. Erosion of cleared areas and soil and overburden dumps leading to sedimentation and pollution of water courses. Possibility of acid mine drainage. Dust created during operations causing visibility problems and loss of agricultural production. Water consumption effects in arid areas.	Noise and vibration effects from machinery. Blast effects. Potential silicosis and respiratory problems.
Deep mining: Basically two types – longwall, and board-and-pillar, but many variations and degrees of mechanization. Access to seams by vertical shaft or drift.	Production of surface spoil heaps with potential erosion effects such as sedimentation and acidification of water courses. Possibility of spontaneous combustion of spoil heaps causing air pollution and tip instability. Mine drainage adversely affecting the water quality of a large area by removing soluble minerals from aquifers and by the acidification of surface water courses. Loss of agricultural productivity over large areas caused by subsidence. Water consumption effects in arid areas.	Noise, vibration and blast effects. Pneumoconiosis and other respiratory problems from dust. Effects of mine gases. Poor working environment – high temperatures, wet conditions, inadequate light. Hard physical work. High accident rate.
Coal transport and storage: Conveyor, slurry pipeline, truck, railway, barge, ship.	Dust effects particularly during transit and at transfer points. Water pollution from disposal of untreated slurry water.	Dust effects.
Utilization: Coking, direct combustion, coal conversion.	Emissions from all processes of particulates, nitrogen and sulphur dioxides, carbon monoxide, hydrocarbons and trace elements. Disposal of liquid effluents, e.g. ammoniacal liquor from coking. All processes produce large amounts of solid waste which can pose problems of erosion, runoff, toxicity and contamination of water courses.	Emissions of noxious gases, heat and dust. Process and End-product related to occupational health risks.

1.4.2 Preparation of coal

Good part of the global production of coal (about 5370 Mt in 2006) undergoes some form of preparation before it is used directly (say, in a pit-mouth thermal power station) or sold. Consumers demand a high degree of consistency in the product sold to them, and the environmental regulations need to be adhered to.

To start with, the ROM coal and the associated refuse material are analysed for their mineralogy, size distribution, hardness, calorific value, coking properties, etc. in order to determine their treatability by the main separation techniques available. ROM coal is crushed using jaw, gyratory or rolls crushers, and then screened to produce different size fractions.

"Clean" coal is lighter, because of its lower ash content. Hence coal separation is effected using the density criterion. Jigging using the water medium is by far the oldest and the simplest method of separation of clean coal. The density of the medium can be raised to the desired level by making use of water-based suspensions of sand, shale, barite, magnetite, etc. The lighter clean coal particles float to the top of the washery cell, whereas the higher density waste particles accumulate at the bottom, with middlings in between. The cycle is repeated until the needed separation is effected.

Separation of coal and waste material can also be effected using cyclones, which may make use of water or some other appropriate (heavier) medium. Occasionally, shaking tables, launders and spirals are used.

Froth flotation could be made use of to clean coal fractions with a maximum diameter of 0.5 mm. In the flotation cell, air is bubbled through the coal slurry, which contains the collector reagents. The aerophyllic coal particles rise to the surface, while the hydrophyllic shale and pyrite particles sink to the bottom of the cell.

1.4.3 Disposal of coal mine tailings

Coal mining industry produces enormous quantities of wastes, considering that the world production of coal is 5370 Mt in 2006. Apart from the solid wastes (shale rock, dolerite, burnt coal, etc.) produced due the mining of coal, coal preparation plants produce large quantities of coarse and fine particles, and contaminated water. The usual practice is to impound the tailings and slurry in the lagoons. As breaching of the lagoons constitute some of the most serious environmental disasters associated with mining, it is critically important that great care be taken in the design of the lagoons. The stability of, and control of seepage from, the lagoons can be ensured by keeping in mind the following design parameters: (i) Construction of the lagoon at or below the ground level, (ii) the banks should have a slope of 34° on the lagoon side, and 26.5° on the outer side, (iii) there should be a toe drain to allow the water table drawdown below the outer slope, (iv) there should be a free board (water surface to the crest of the lagoon bank) of at least one metre, (v) the inner surface of the bank should be capable of withstanding erosion due to wave action, (vi) there should be provision for drawing off the supernatant, as also rainwater due to abnormally heavy rainfall, etc. (Chadwick et al., 1987, pp. 126–127). The supernatant water from the lagoons may be either recycled, or discharged into the natural waterways after treatment.

1.4.4 Subsidence

Mining involves the extraction of large quantities of rocks, liquids and gases from the depths of the earth, and therefore causes damage not only on the surface but also to depths of hundreds and thousands of metres.

The extent of subsidence varies from a few mm (due to withdrawal of waters from underground aquifers) to more than 6 or 7 m (arising from the extraction of coal from thick seams or due to underground fires). Subsidence may cause direct air circulation due to goaved-out areas, and may cause spontaneous combustion and fires within the goaf areas. Fires starting in one seam in a coal mine may spread to seams above and below it, and to seams in the neighbouring mines (as has happened in the Jharia–Raniganj coalfields in India). The presence of faults and dykes/sills and abandoned old workings may accentuate the problem of underground fires. The subsidence triggered by fires invariably spreads fast. As a consequence of subsidence movements in the underlying seams, the overlying coal seams may be rendered unworkable.

The following impacts of subsidence are common: formation of depressions in the surface, abrupt changes in the road gradients, damage to underground pipelines and cables, damage to surface buildings, plants and pylons, disturbance in the aquifers leading to reduced and contaminated flows, retardation in the growth of vegetation due to reduced availability of water, waterlogging in the central part of subsided area, contamination of surface air due to emissions from the underground fires, flooding of underground mines due to the development of ruptures in the underground waterbodies, etc. (Sengupta, 1993, p. 28).

In the case of surface mining, the extent of geomorphic change is conditioned by the thickness of the overburden covering the deposit, the quantity of barren rock that needs to be excavated per unit of the extracted mineral and the area of the mine. Underground mining may lead to surface subsidence with consequent disturbance to surface runoff, formation of water-filled depressions, and flooding in the coastal areas or near lakes. Mining under water generally involves dredging of loose sediments.

When the material is removed by underground mining, it triggers ground movement and the consequential deformation of the surface. The nature and extent of deformation depends upon the following parameters: (i) geometry of the mineral deposit – the mining of a massive, flat-beddded deposit will cause more deformation than a vein deposit, (ii) the method of mining – longwall mining is more likely to lead to subsidence than room-and-pillar mining, (iii) the nature of the mineral deposit, and the nature of the overlying strata – there are less chances of deformation if the mineral deposit and overlying rock are competent, than when they are incompetent.

Subsidence may lead to the following damages:

- i Fractures: The fractures may be continuous or discontinuous, and may range in size from millimeters to meters. They can cause severe damage to buildings and installations,
- ii Surface trough: Continuous deformation may lead to the formation of a surface trough. Uniform displacement does not generally cause much damage. Differential displacement could adversely affect the groundwater flow, and could bring about changes in the gradients of roads, railways, water or gas pipelines, etc.

Back filling of underground coal mines by hydraulic stowing of river sand is a common practice in India. Such a stowing reduces the surface subsidence below 10%, protects the aquifers, habitats, farms and fields. The township of Raniganj and the villages around it in the famous Jharia Coalfield in Bihar, India, did not suffer much damage for 75 years so long as the pillars in the underground mines were preserved. The unscientific depillaring of the thick coal seams ("slaughter mining") triggered subsidence, mine fires and environmental pollution in the area. Due to underground mining in the Jharia Coal Field, surface subsidence took place over an area of 32 km^2. The formation of goaf (void space) beneath the surface led to the formation of cracks on the surface, 5 to 10 m long, and about 0.5 m wide. There are also depressions caused by caves-in. At some places, smoke and gases emanate through the cracks. It has been estimated that about 34 Mt of coking coal has already been lost because of underground fires. About 70 fires (out of 110) are still active and blocked out about 50 Mt of coking coal which hence cannot be worked.

There may be failure of the pit walls after an open-pit mine is abandoned. It is therefore necessary to designate a safety zone around the mine. The safety zones and other measures are designed taking into account the geological, structural, geotechnical and climatic conditions.

Underground gasification of coal in the former Soviet Union (involving a coal seam 5–15 m thick at a depth of 100–130 m, in an area of 1 km^2) gave rise to one of the biggest landslides in the world, with a volume of 0.8 km^3 spread over an area of 8 km^2 (Vartanyan, 1989, p. 42).

Landslides and rock and mud flows are common in the mining areas, especially when the wastes are dumped on the hillsides. For instance, the volume of the mudflow arising from the Yimen copper mine in China, was of the order of 200,000 m^3. Another mudflow of the volume of 100,000 m^3 from a mine in Yunnan, China, destroyed 6.2 km^2 of fertile land on the plain.

Four types of remedial measures are available for mitigating the subsidence in an abandoned mine: point support, local backfilling, areal backfilling and strata consolidation (Sengupta, 1993, p. 439). In the point support method, a large number of grouting holes are drilled, and grouting materials are injected to form the grouting piles and support the roof. Depending upon the engineering method used, the point support method could take the form of gravel columns, grout columns, fly ash grout injection, and fabric formed concrete.

The local backfilling does not involve drilling the grouting holes. In this method, small, shallow potholes or surface cracks are filled with gravel, refuse and dirt, by direct dumping.

Areal backfilling is meant to protect large urban areas (of the order of hundreds of hectares) from subsidence. This is accomplished by injecting into the underground openings large quantities of grouting materials, such as sand, gravel, coal refuse, mine tailings, fly ash, etc. under pressure.

In the strata consolidation method, the shallow strata beneath the damaged surface structure are grouted or bound into a single rigid unit. If the subsidence continues, the consolidated structure will move as a rigid body without being damaged. There are several ways of bringing about consolidation, such as the use of polyurethane binder, cement grout pad or rock anchor.

1.4.5 Coal dusts during the coal cycle

It has been estimated that the progressive disintegration of one cm^3 of lump of coal may form 10^{12} particles, and could spread over 283 m^3 of working ambient. Because of their extremely small size (0.2–10 μm), they are invisible to the naked eye, and could remain suspended in the air for a long time. For this reason, the ambient air loaded with these dust particles appears deceptively clear. But this dust is respicable and could cause pneumoconiosis, bronchitis and severe dyspnea (shortness of breath).

The coal mine dust contains a wide range of non-coal particles, such as silica, naphthalene, and several Polynuclear Aromatic Hydrocarbons (PAHs). It has been estimated that a mine producing one million tonnes of coal annually, about a tonne of toxic elements such as, arsenic, beryllium, cadmium, fluorine, lead, mercury, etc. are liberated as dust or gas where coal is cut from the working face. The dust problem is greater in arid and tropical climates.

Coal is mainly transported by rail and truck. In countries, which have canals and navigable rivers, coal is transported by towed barges. Coal is transported by sea. The transport of coal involves emission of fugitive dust. It has been estimated that 0.2 kg/t each is emitted during loading and unloading operations, and the loss in transit may be 0.05–1% of total coal (excluding loss to spillage and pilferage).

Szabo (1978) made the following estimates of the atmospheric emissions from a unit train carrying 1143 t of coal making a round trip of 985 km. (in terms of kg/trip): Particulates: 345; SO_2: 780; NO_2: 4855; Hydrocarbons: 2075; CO: 935; Particulates during loading: 2285; Particulates during unloading: 2285; Fugitive emissions in transit: 5700.

Coal is beneficiated to improve the heat content, while at the same time reducing the content of mineral matter, including pyrite. In the case of the Gondwana coals, which are of drift origin, the mineral matter is intimately interspersed in coal, and it is virtually impossible to remove all sulphur and other mineral impurities present in the coal. All the steps involved in the beneficiation process, namely, comminution, sizing, cleaning, dewatering, drying, etc., all contribute to pollution. Huge quantities of water used in washing get polluted, and need to be treated before recycling.

Coal is carbonized in coke ovens to produce hard coke suitable for the steel industry. The process produces a series of primary byproducts, such as coal tar, ammonia liquor or ammonium sulphate, crude benzole and coal gas. Coal tar itself is a complex mixture of aromatic hydrocarbons, such as benzene, naphthalene, anthracene, pheanthrene and their homologues.

Carcinogenicity of coal tar derivatives depends upon the temperature of carbonization. Distillation products of tar at high distillation temperatures of around 800–850°C, are composed of Polynuclear Aromatic Hydrocarbons (PAHs) (such as BP – benzo (α) pyrene, DBA – dibenzo (α) anthracene, or DBP – dibenzo (α) pyrene), which are known carcinogens. It has been observed that roofing workers who routinely handle coal tar and pitch products, contracted skin cancer four times, and lung cancer fifteen times, more than the control group. The carcinogenicity of anthracene fraction of coal tar arises from its high content of benzo pyrene (27 g per kg).

The combustion of coal leads to the production of a variety of pollutants, such as the oxides of sulphur, nitrogen and carbon, as well as particles of ash that get entrained in flue gases.

Sulphur dioxide is by far the most serious pollutant, because it has impacts on human health, and causes acid rain, which damages vegetation and buildings, etc. In the atmosphere, sulphur oxides get converted into highly corrosive sulphuric acid. Sulphur may be present in coal in two forms: (i) organic sulphur, and (ii) pyritic sulphur. About 70–80% of sulphur present in the Indian coals is said to be in the organic form. When coal is subjected to combustion (as in thermal power stations), organic sulphur is more readily converted to SO_2 than pyritic sulphur. Stationary combustion sources account for 70% of the sulphur emissions. The sulphur emissions from the coal industry exceed the emission of sulphur compounds from natural processes world wide.

Nitrogen oxides (NO_x) are produced when nitrogen naturally present in coal reacts with oxygen in the combustion chamber. In the atmosphere, NO gets readily converted to more toxic NO_2, and the production of highly corrosive nitric acid. Nitrogen oxides can have health effects, can damage crops, and lead to the production of secondary pollutants. Fossil fuel combustion accounts for about 95% of the anthropogenic production of NO_2. Los Angeles type of smog is produced when NO_2 and hydrocarbons react photochemically under conditions of atmospheric inversion. NO_x is a radiatively active gas, and has a role in global warming and the depletion of the ozone layer in the atmosphere ("Antarctic Ozone Hole").

Two main groups of hydrocarbons are emitted during coal combustion: (i) Low molecular weight species, derived from the volatile matter present in the raw coal, and (ii) High molecular weight species which are emitted as fine particles, or more commonly adsorbed on fie particles. In moderately large boilers (say, 25 MW), the volatile fraction (measured as CH_4) and particulate fraction (measured as benzene soluble organics) is of the order of a few milligrams per m^3 of flue gas.

Pre-treatment of coal, fluidised bed technologies and the advanced, low-polluting coal combustion system, called Low NO_x Concentric Firing System (LNCFS), are making it possible to make efficient use of high-ash coal, with reduced emission of gases.

Burning waste tips discharge noxious gases into the atmosphere. A medium-sized burning waste tip can emit annually: 620–1280 t of SO_2, 11–30 t of NO_2, 330–500 t of CO, and 230–290 t of H_2S. There were instances where a burning waste tip polluted the air for about 2 km around. As coal contains sulphur in the organic form of pyrite (FeS_2), the burning waste tips of coal mines discharge large quantities of SO_2 and H_2S. It has been estimated that a total of 175 million tonnes (Mt) of gases are discharged from all the waste tips of the coal mines in the world. This amount includes 23 Mt of CO, 2 Mt of SO_2, 0.9 Mt of H_2S and 0.3 Mt of NO_2.

Blasting operations in quarrying and opencast mining pollute the atmosphere through dust and gases. For instance, if 200–300 t of explosives are used for blasting in a particular operation, the volume of the dust generated may be of the order of 20–25 million m^3. Blasting operations also discharge nitrogen compounds, such as NH_3 and NO_2, into the atmosphere. One tonne of explosives produce 40–50 m^3 nitrogen oxides.

The discharge of dusts and gases into the atmosphere is bound to have health effects. It has been reported that in the highly industrialized Ruhr District of Germany, the incidence of respiratory diseases is 60% above the national average.

High intensity noises, which are generated during blasting and the operation of the mining machinery, are hazardous to human health.

It is now a common practice in most of the mining areas in the Industrialized countries to monitor the air continuously, for (1) the discharge, content and precipitation of dust and the concentration of heavy elements like cadmium, lead, etc. in air (pg m^{-3}), and (2) the concentration of gases, such as SO_2, CO_2, H_2S, NO_x, NH_3 etc., in the air. When the ambient levels rise beyond the prescribed loads, corrective action is taken promptly to bring down the concentrations to the acceptable levels.

Mining activity adversely affects the biosphere through the loss of the farming land, and through the degradation of the ecological systems. Microclimate in the mining area is also affected. Land subsidence in the areas of underground mines, and the creation of waste tips lead to the destruction of the vegetation, and the death of animals and birds. It should not be forgotten that man is a part of the biosphere, and he cannot avoid being adversely affected when the vegetation and the animals are degraded.

Coal mines generally use timber for roof support. Experience shows that a coal mine with a production of (say) 400,000 tonnes per annum uses 9,000 to 12,000 m^3 of timber, which is usually obtained from the local forests. Thus, local forests tend to disappear unless tree crops are grown to provide the wood needed on a continuing basis. Dewatering of the mines may lead to significant changes in the vegetation in the mining area.

Plants are particularly susceptible to atmospheric pollution. The intensity of photosynthesis is adversely affected by pollutants such as, sulphur dioxide, carbon monoxide and hydrocarbons, which cause necrosis of leaves, inhibition of growth and early leaf fall. Eventually, the plants wither and die. Space photographs clearly show the devastation of the vegetation caused by mining in different parts of the world.

1.4.6 Environmental consequences of coal use in the steel industry

About 13% (~717 Million tonnes) of the hard coal produced in the world is used in the iron and steel industry. Steel industry is known as a dirty industry, and this is partly attributable to coal used in the industry. Coal dusts arise in the following units:

Stockyards and handling areas: In the steel industry, unloading, storage, recovery and transfer operations in the case of iron ore, coal, coke, limestone, lime and also slag, take place all the time, creating dust pollution. The following techniques can be made use of to collect and clean the dust (UNEP Tech. Review, 1986, pp. 49–51): (i) installation of hoods above the conveyor belts to suck in the air, and extract the dust from it (on the analogy of a vacuum cleaner), (ii) dozing the coal in the stockyard for smoothing and compacting of coal, (iii) spraying the stockpiles with water, with or without surfactants, (iv) covering the stockyards with a roof, and (v) building walls to serve as wind-breaks.

Coke ovens: Pollution occurs during the preparation of the coal, charging the coal into the oven, the coking process itself, removal of the coke from the oven, quenching it, screening and handling. Dirty, black dust is visible all around. The quantities of dust produced are highly variable, and are dependent upon the properties of coal, the design of the coke oven, and operational procedures.

The progress that has been made in the techniques of reducing the dust pollution is illustrated with two examples from coke pushing and the coke quenching operations. For instance, there are three possible ways of recovering waste gases and extracting dust from them in the case of coke pushing operations: a wholly mobile technique, with a mobile hood and dust cleaner coupled to the coke car, a wholly stationary technique, in which stationary dust cleaner in a covered bay cleans up the dust, and a combination technique, with a mobile hood connection running along the length of the battery, and linked to a stationary dust extraction system on the ground.

Similarly, there are wet or dry methods of limiting the emission of particulates in the coke quenching tower. In the case of wet methods, the quantity and quality of cooling water, and the system of baffles have to be carefully controlled. To avoid the hassles of treating large quantities of used water, dry techniques of quenching are being increasingly used. The dry techniques have two merits: they not only avoid the emission of particulates and gaseous pollutants, but also allow the recuperation of heat from the hot coke.

The extent of generation of pollutants in the earlier coke ovens, and how the installation of modern cleaning equipment can drastically bring down the dust pollution in the coke oven is indicated in Table 1.4.2.

Sinter plant: The dust collection system in the case of the sinter plant consists of electrostatic precipitator for the main waste gases, and bag filters for the collection of dust in the premises. Two 700 kW ventilators are needed to take care of air flow of 2 million m^3/hr over a 400 m^2 grid surface.

Blast furnace: Blast furnace has always been regarded as a major source of pollution. The top gas is highly noxious, with 25% content of carbon monoxide, and it is discharged with 40 kg of dust per tonne of hot metal. Top gas is, however, a source of

Table 1.4.2 Effectiveness of cleaning equipment in the case of coke ovens.

Operations	*Dust pollution* before *treatment, in g/t of coke*	*Dust pollution* after *treatment, in g/t of coke*
Coal charging	150	10
Coke pushing	400	10
Coke quenching	350	5
Coke handling	1,500	50
Total	2,400	50

Source: UNEP Technical Review, 1986, p. 51.

energy, and the current practice is to recover the energy in the top gas, and remove the dust contained in it, so that the top gas is never discharged into the atmosphere.

Pig iron refining plants: Pig iron is refined into steel by the removal of impurities contained in it, such as, silicon, carbon and phosphorus, through the Bessemer process or open hearth furnace. Bessemer process is obsolete, and the importance of open hearth furnace is decreasing. Currently, steel refining is mostly done through oxygen converters. The emissions at the mouth of the converters are composed of CO, and lesser amounts of CO_2, and substantial concentration of fine particles of iron and oxides, called "red fume" (about 150 g/Nm^3). There are two environmentally acceptable ways of handling the emissions: (i) recovery without involving the combustion of CO, with the combustible gas being recycled into the energy circuit of the works, and (ii) recovery with the air combustion of CO, whereby the energy is extracted in the form of steam.

Dust cleaning is usually done by the wet method involving Venturi scrubbers using high or low pressure drop. Electrostatic precipitators can bring down the dust content from 120 mg/Nm^3 to 10 mg/Nm^3. As considerable progress has been made in the extraction of dust from the waste gases, the focus is now on the fugitive emissions in the oxygen steel making plant. The order of fugitive dust emissions from an oxygen steelmaking plant is indicated below (in terms of g/t of steel): Rehandling of pig iron (19), desulphurization of pig iron (16), converter charging (140), converter blowing (24), Miscellaneous (8), total 187. The problem in the case of fugitive gases is not so much the extraction of dust from them (which is a standard procedure), but the difficulty in forcing the waste gases into a hood at the front of the converter. Extremely high suction velocities (e.g. 15 m/s) and throughput (e.g. 300,000 Nm^3/h) are needed to achieve this.

Dust cleaning does not come cheap. The cost of investment of dust cleaning facilities is about 15% of the cost of the steel works itself, and the operating costs are high.

Scrap melting plants: There are essentially two kinds of scrap melting methods – open hearth process, which takes its heat input from the burners, and the electric arc method, which uses electricity. In the case of the open hearth furnace, if the intensity of steel making is low, the rate of emission of fumes is limited, and it may not be necessary to install cleaning systems. However, if high top blow technology is used, the red fume emission would be high, and cleaning systems, such as electrostatic precipitators, will have to be installed.

In the case of electrical furnaces, there are two methods of fume collection: (i) "direct" collection of fumes from the fourth hole into the furnace roof (three holes are taken up by electrodes), and (ii) secondary collection of fumes to capture those gases which are emitted in charging the furnace, and tapping from it. In the case of a 80 t furnace, the throughput rates are about 1000 Nm^3:h/t for the collection from the fourth hole, and 4000 Nm^3/t for secondary fumes. Dust cleaning is done by bag filter, fitted with needle felts. High-energy scrubbers have been developed for direct collection only.

Reheating furnaces used in rolling mills are energized by blast furnace or coke oven gas, or natural gas or fuel oil. Particulate pollution is minimal, and hence no dust cleaning is needed.

1.4.6.1 Techniques for reducing gaseous pollutants in the steel industry

Control techniques have been installed in most steel mills to reduce the particulate emissions. The emphasis now is the reduction of gaseous pollutants. Desulphurization and denitration constitute important techniques for the elimination of gaseous pollutants in the iron and steel industry (source: UNEP Technical Review, 1986, pp. 54–55):

Desulphurization: Can be effected in two ways, by chemical treatment through alkaline products, such as, calcium, sodium, magnesium, ammonium products, etc. or by physical treatment involving adsorption using activated carbon. Japan achieved desulphurization of 90% using the milk of lime for desulphurization. The gases are scrubbed with calcium (milk of lime or calcium chloride solution) or ammonium based liquid, to recover SO_2 and SO_3 in the form of calcium and ammonium sulphate. The new practice is to link several physical purification processes together – for instance, it is possible to capture residual dust and SO_2 together by using bag filters charged with lime.

Coal dusts produced in the course of mining and transportation of coal lead to silico-anthracosis of coal workers. Arseniasis is caused by the inhalation of smoke produced when arsenious coal is used in domestic cooking. An examination of the statistical data (for USA, 1995) in regard to fatalities, nonfatal days lost (NFDL), total accident incident rate, and severity measurements (SM) for underground and surface mines by sector (Grayson, 1999, p. 94) leads to the following conclusions: (i) Among all the mining activities for various minerals, the most hazardous is the underground mining of coal, and (ii) The underground mining of coal has higher severity measure than the corresponding figure for surface mining.

Table 1.4.3 indicates that coal mining is characterized by the highest incidence of occupational illnesses, such as, lung diseases and trauma disorders, relative to mining for other minerals. By improving the working conditions in the mines, the number of silicosis cases per year came down from 857.4 during 1968–78 to 284.5 in 1991–92 in USA. Similarly, the number of cases of pneumoconiosis per year, which was 2374.8 in 1968–78, was brought down to 1852.0 per year in 1991–92.

Table 1.4.3 Occupational illnesses in mining by sector (US data, 1995).

Type/sector	*Coal*	*Metal*	*Non-metal*	*Stone*	*Sand/gravel*
Skin diseases	3	4	1	12	3
Dust diseases – lung	207	8	5	9	2
Respiratory – toxic agents	8	1	2	1	0
Poisoning	3	1	0	3	0
Disorders-nontoxic physical Agents	2	12	3	15	5
Disorders – repeated trauma	214	109	32	49	22
All others	21	2	3	5	1
Total	488	137	46	94	33

Source: Grayson, R.L., 1999, p. 95.

Table 1.4.4 Hazard prevention measures.

Hazard	*Principle of prevention*	*Preventive measure*
Dust	Suppression at the source, Dilution in the air, Suppression in the environment	Wetting the coal face, Ventilation, Surfactants on the floor
Noise	Substitution	Other machinery
Heat	Reduction	Ventilation and air-conditioning
Heavy work	Elimination, Substitution	Mechanization/automation, Ergonomic design of work
Vibration	Elimination	Remote control
Falls of ground	Elimination	Support to roof and walls
Dangerous machines	Substitution, Segregation	Maintenance/replacement, Machine guarding
Blasting	Suppression at source, Dilution of air	Wet methods, Ventilation
Gases	Disposal, Dilution	Extraction, Ventilation

Source: Chadwick et al. 1987, p. 223.

There are three *E*'s of mitigation: Education, Engineering and Enforcement. The goal of the mining industry should be to ensure that the workers could work their entire career without incurring death, disability or serious injury.

Table 1.4.4 lists the hazard prevention measures in the case of the coal cycle (source: Chadwick et al., 1987, p. 223).

1.5 WASTES FROM COAL INDUSTRIES

1.5.1 Solid wastes

When the soil or sediment cover is removed in the process of quarrying, their filtering and attenuation capabilities would have been lost, thus exposing the groundwater to greater risks of pollution. Groundwater could also be contaminated due to some ancillary activities associated with quarrying, such as, accidental spillages of fuel oil, leakages from storage tanks or toilets for workers, or draining of water from the surrounding areas into the quarry, etc.

Solid wastes arising from the mining of coal and lignite tend to contain pyrite (FeS_2). Under oxidizing conditions, and in the presence of catalytic bacteria, such as *Thiobacillus ferrooxidans*, pyrite gets oxidized into sulphuric acid and iron sulphate. Thus, surface runoff and groundwater seepages associated with waste piles tend to be highly acidic, and corrosive. The discharge of such waters (known as Acid Mine Drainage or AMD) into streams destroys the aquatic life, and the stream water is rendered non-potable.

Table 1.5.1 Solid wastes from mining.

Source	*Potential characteristics of leachate/effluent*	*Rate of effluent or solid waste production*
Coal-mine drainage	High total dissolved solids. Suspended solids. Iron. Often acid. May contain high chlorides from connate water	10^5–10^7 m^3 y^{-1}
Colliery waste	Leachate similar to mine drainage waters	10^5–10^7 t y^{-1} of wastes per colliery. Quantity of leachate depends on climate
Power generation (thermal)	Pulverized fuel ash. Upto 2% by weight of soluble constituents, sulphate. May contain Concentrations of Germanium and Selenium. Fly ash and flue gas scrubber sludges. Finely particulate, containing disseminated heavy metals. Sludges of low pH unless neutralized by lime addition.	10^4–10^6 t y^{-1}

Source: Laconte & Haimes, 1982.

The solid wastes produced in mining activities which could contaminate water resources through leaching and effluent production, are listed in Table 1.5.1. (source: Laconte & Haimes, 1982).

Fly ash is reactive because of its high surface area: volume ratio. Leaching of the fly ash may produce effluents containing toxic elements, such as, Mo, F, Se, B and As. Low pH leachates from fly ash may give rise to problems of iron floc formation in surface waters. When the flue gases are scrubbed, the resulting sludge will typically contain cyanide and heavy metals. Its pH will be low, unless neutralized by lime. It has been reported that mixtures of sludge, lime and fly ash will set rapidly to a load-bearing, low-permeability, solid which is not easily leachable. Two benefits accrue from this process – on one hand we will have a useful construction material, and on the other, we would have minimized the pollution risk.

1.5.2 Liquid wastes

How industrial effluents arising from coal mining affect the environment is illustrated with the example of coal mining in the Damodar River basin in eastern India.

Damodar river basin in eastern India contains about 46% of the coal reserves of India. Apart from underground and opencast mines of coal, the area has numerous coal-based industries, such as, steel, chemical and fertilizer plants. Fortunately, the pyrite content of coal is not high. The water of the Damodar River is contaminated by (i) huge volumes of polluted water from underground mines – for instance, Bharat Coking Coal Limited (BCCL) mines in Jharia pump out 300 gallons of mine water daily, (ii) runoff water leaching the overburden dumps, (iii) industrial effluents from coal-based plants. Large amounts of fly ash and fine coal particles discharged by the thermal power plants and washeries settle down to the bed of the river and hinder the growth of the biota. About 25 million tonnes of coal is washed annually in the area, involving the use of about 2000 t of pine oil. Large amounts of suspended solids, oil and grease arising from the washeries are discharged into the river. The coke oven plants serving the steel industry, release highly toxic substances like phenols and cyanides. The low DO contents and high content of heavy metals in the effluents make it almost impossible for biota to survive in the river water.

The quality of the water in the upstream part of the Damodar river is fairly good with TSS in the range of 18–168 mg/l. But serious deterioration of water quality occurs when the industrial waters from Patratu thermal power plant, and the steel plant at Durgapur are discharged into the river. But people who live in the area have no option except to drink the contaminated water. A health survey conducted in 1993–94 showed high incidence of water-related diseases, such as, dysentery, diarrhea, skin infections, jaundice, typhoid, etc. (Tiwary et al., 1995).

1.5.3 Emissions due to coal industries

Energy industries (particularly coal-fired, thermal power stations produce huge quantities of gaseous pollutants (Table 1.5.3; source: El-Hinnawi, 1981). The global

Table 1.5.2 Summaries the physico-chemical characteristics of the industrial effluents in the Damodar river basin.

Parameter	*IS:2490*	*Coke oven plant*	*Thermal power plant*	*Coal washery*	*Steel plant*
Flow rate (m^3/hr)	–	10.8–72	81–33,768	30–810	112–7,245
pH	5.5–9.0	7.67–8.62	7.98–8.46	7.31–7.49	2.98–7.3
Temp. (°C)	40.0	29.2–40.0	28.0–39.0	29.1–31.2	20.0–36
TSS	100	447–636	780–20,400	160–83,560	334–1,465
TDS	2,100	486–581	206–398	304–775	16–186
DO	–	0.5–2.2	3.98–5.89	2.61–3.84	2.86–7.52
BOD	30	7.8–81.0	3.0–22.0	4.0–10.0	8.0–32.0
COD	250	208.3–331.2	359–5,192	2,073–63,848	55–1,098
Phenols	–	0.1–0.2	Nil	Nil	0.02–1.13
Cyanide	0.2	0.002–0.2	Nil	Nil	0.01–0.07
Oil & grease	10	0.98–1.26	0.7–1.8	0.4–32.5	0.86–112.4
Fe	–	2.89–6.54	5.61–83.6	0.11–181.3	2.17–37.0
Mn	–	0.28–0.45	0.08–1.19	0.06–6.20	0.14–0.41
Cr	2.0	BDL-0.05	BDL-0.17	0.18–0.43	BDL-0.34
Pb	0.1	0.0–0.5	BDL-0.09	0.20–0.75	BDL-0.06
As	0.2	BDL	BDL	BDL-0.02	BDL
Cd	2.0	BDL	BDL	BDL-0.2	BDL-0.12

BDL—Below Detection Limit.
All parameters are expressed in mg/l, except flow rate, and pH.

Source: Tiwary et al. 1995.

Table 1.5.3 Average emissions from 1000 MW coal-fired and oil-fired stations (in tonnes).

	Coal-fired station	*Oil-fired station*
Sulphur dioxide	110,000	37,000
Nitrogen oxide	27,000	25,000
Particulates	3,000	1,200
Carbon monoxide	2,000	710
Hydrocarbons	400	470
Ash	360,000	9,000

Source: El-Hinnawi, 1981.

Table 1.5.4 Heavy element emissions from coal and oil combustion (10^9 g y^{-1}).

Element	*Total*	*Coal*	*Oil*
As	23.6	0.7	0.002
Se	1.1	0.42	0.03
Cd	7.3	–	0.002
Hg	2.4	0.0017	1.6
Pb	449	3.5	0.05

Source: Compilation by Fergusson, 1990.

emissions of heavy elements and the contribution by the combustion of coal and oil (in terms of 10^9 g y^{-1}) are given in Table 1.5.4 (compilation by Fergusson, 1990).

1.5.4 Loss of biodiversity

Large scale coal mining disturbs the biodiversity and productivity of the ecosystem. The huge accumulations of overburden dumps at Mandman and Mudidih areas in the Jharia Coal Field, Bihar, India, reduced the vegetation cover from 65% to 39% and the fallow land and pasture from 9.1 to 3.1%, during the period, 1925 to 1993. Table 1.5.5 (source: Tewary, Singh and Dhar, 1995) shows how these dumps affected the composition of the plant species and their biomass.

1.5.5 Beneficial use of mining wastes

The volume of wastes generated in the process of mining increases with increased volume of mining activities, and increased mechanization. No-waste and low-waste mining technologies can in principle bring down the volume of wastes that need to be disposed of, but there is little doubt that wastes in mining cannot be avoided altogether. The use of waste rock for back-filling, recycling, and the large-scale use of wastes for the construction of roads, buildings and other civil engineering structures are some of the ways by which the wastes can be used beneficially.

Table 1.5.5 Plant communities in disturbed sites in Jharia Coalfields, Bihar, India.

Site	*Plant communities and their abundance (%)*	*Total plant biomass (g/m^2)*
Unmined		
Mandman	*Andropogon* (40), *Eleusine spp* (20)	380
Mudidih	*Ergrostis* (30), *Andropogon spp.* (26)	456
Mined		
Mandman	*Ergrostris* (24), *Panicum* (22), *Tridex* (14)	230
Mudidih	*Saccharum* (25), *Eupatorium* (22), *Leonotis* (22)	270

Source: Tewary, Singh and Dhar, 1995.

Coal mining wastes: Taking the mining industry as a whole, there is little doubt that coal mining produces the largest volume of solid wastes. Mine gangue and coal-washing tailings are being increasingly used as filling materials, additives in concrete and for agricultural purposes.

The gangue material in coal waste tips generally has a porosity of about 35%. The relatively high combustible content of the waste coupled with its high porosity, makes the waste liable for spontaneous combustion. It has been estimated that 40% of the 17,000 rock waste tips in the world, are burning. Smoke from the burning tips pollutes large areas around them. An ingenious way to reduce the porosity of the waste tips and thereby reduce their proneness for spontaneous combustion is the addition to waste tips of fly ash from the wastes of the thermal power plants. In this manner, one kind of waste is made use of to reduce the environmental harm from another kind of waste!

After strengthening, the gangue material from the coal mining industry can be used in the construction of road embankments and railway lines, landscaping of building sites, and earth dams. The porosity of the gangue is reduced and the strength increased by compaction with bulldozers and addition of pore-filling materials, such as fly ash from power plants, sand, and flotation tailings. By this process, the porosity can be reduced to 20%, and the density increased to 2.1 t m^{-3}.

Clays with high content of organic matter can be used to make material called karamzite. In Belgium and France, mine gangues and coal washing tailings are made use of to fabricate commercial building materials, trademarked AGRAL. The gangue material can also be made use of to make bricks, and as aggregates for light weight concrete. For instance, the brick-works of "Lvovstrojmaterialy" in Ukraine which produces 300 million bricks a year, found that the use of 10% coal wastes has reduced the consumption of fuel by 20–25%, besides improving the quality of bricks.

The CSIR Laboratories in India (principally, the Central Building Research Institute, Roorkee, and the Regional Research Laboratory, Bhopal) have developed innovative approaches for the use of fly ash from the coal industry and red mud wastes from the aluminium industry (vide CSIR Rural Technologies, 1995, pp. 83–88).

Clay may be mixed with fly ash (to the extent of 10–40%) and made into bricks, which can then be fired in conventional Bull's kiln, or intermittent type kilns at a temperature of 950 to 1050°C. The use of fly ash permits the production of 40% more additional bricks from the same quantity of soil. The clay-fly ash bricks have lower bulk density, better thermal insulation and reduced dead load on the brick masonry structure. These bricks can be used for all types of construction, where normal clay bricks are used.

In areas where good quality clay is not available, fly ash-sand-lime bricks can be made. Fly ash could be used to the extent of 70%. The bricks will have a wet compressive strength of 100–200 kg cm^{-2} and water absorption of 10 to 20%. Drying shrinkage (0.01–0.05%) and thermal conductivity are comparable to those of the clay bricks. Unlike the clay bricks, the fly ash – lime – sand bricks do not need drying.

The lime – fly ash blends can be used as stabilizers in road construction. For granular soils, 3–6% lime and 10–25% fly ash should be used. For clayey soils, 5–9% lime and 10–25% fly ash, need to be used.

Black coal flotation sludges can be dried to reduce their moisture content to 8 to 10%, and the resulting product can be burnt in the thermal power plants. Brown coal sludges are finding numerous uses in agriculture. When added to the soil, the humic acids contained in coal form organo-mineral humus and sorption complexes and become repositories of nutrient elements. This improves the structure, pH and fertility of the soil. In Russia, the combination of manure and high-ash coal (the so-called mineral manure) proved very successful. In Hungary, brown coal dust mixed with manure is used as a fertilizer. Coal waste can be used as bio-organic mineral fertilizer.

Coal mining industry produces enormous quantities of wastes, considering that the world production of coal is 5370 Mt in 2006. Apart from the solid wastes (shale rock, dolerite, burnt coal, etc.) produced due the mining of coal, coal preparation plants produce large quantities of coarse and fine particles, and contaminated water. The usual practice is to impound the tailings and slurry in the lagoons. As breaching of the lagoons constitute some of the most serious environmental disasters associated with mining, it is critically important that great care be taken in the design of the lagoons. The stability of, and control of seepage from, the lagoons can be ensured by keeping in mind the following design parameters: (i) Construction of the lagoon at or below the ground level, (ii) the banks should have a slope of 34° on the lagoon side, and 26.5° on the outer side, (iii) there should be a toe drain to allow the water table drawdown below the outer slope, (iv) there should be a free board (water surface to the crest of the lagoon bank) of at least one metre, (v) the inner surface of the bank should be capable of withstanding erosion due to wave action, (vi) there should be provision for drawing off the supernatant, as also rainwater due to abnormally heavy rainfall, etc. (Chadwick et al., 1987, pp. 126–127). The supernatant water from the lagoons may be either recycled, or discharged into the natural waterways after treatment.

In some countries, such as Germany and Poland, colliery spoils are tipped with domestic wastes (Figure 1.5.1; source: Skarzynska and Michalski, 1999, p. 189). Untreated coal colliery spoils are used as bulk material for various types of earth works, such as embankments of roadways, railways, rivers and dams. The water contained in the dumps and infiltrating through the dumps, is likely to be contaminated. In order to prevent such contaminated water from polluting bodies of freshwater, polyethylene sheeting or clay screens should be incorporated with drainage to remove the infiltrating water (Figure 1.5.2; source: Skarzynska and Michalski, 1999, p. 196).

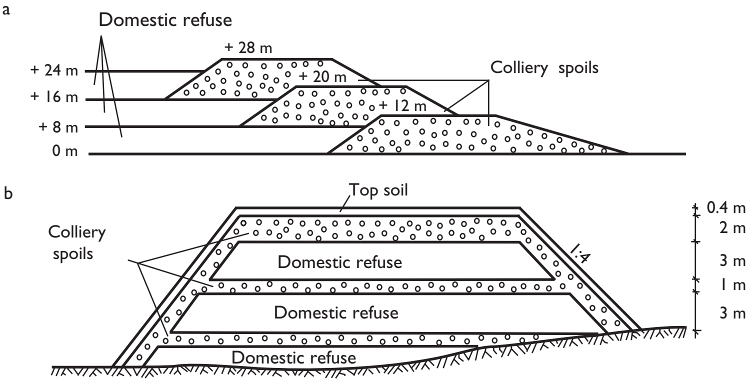

Figure 1.5.1 Joint tipping of colliery spoils and domestic refuse.

Source: Skarzynska & Michalski, 1999, p. 196.

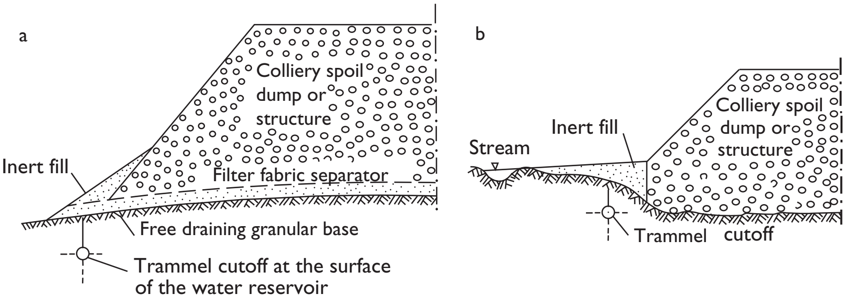

Figure 1.5.2 Design of trommel cutoff.

Source: Skarzynska & Michalski, 1999, p. 196.

1.6 HEALTH HAZARDS DUE TO COAL INDUSTRIES

Mining is undoubtedly the most hazardous industrial occupation. For instance, during the period 1980–89, mining ranked as the number one in USA with respect to the average annual rate of traumatic fatalities (with the rate of 31.91 for 100,000 workers), as against 25.61 for the construction industry, 23.30 for the transportation/communications/public utilities industries, and 18.33 for the agriculture/forestry/fishing industries. There are two kinds of health impacts associated with mining: immediate impacts such as accidents, and accumulative and progressive impacts such as stress and pneumoconiosis. Opencast mining is generally less hazardous than underground mining. Industrialised countries tend to use highly automated mining systems, which not only employ lesser number of workers (who have to be highly skilled), but also have the effect of drastically reducing the hazards to which they are exposed. Developing countries cannot afford such safer mining systems, so much so that mining accidents are a common occurrence in developing countries such as China and India.

There are four types of health hazards associated with coal mining (see the excellent account by Chadwick et al., 1987, pp. 203–236, from which the following account has largely been drawn).

i Physical hazards, e.g. coal dust, silica dust, excessive heat, noise, heavy physical work, contorted body posture,
ii Chemical hazards, e.g. carbon dioxide, carbon monoxide, methane, nitrogen oxide gases,
iii Biological hazards (applicable in some developing countries), e.g. fungus, hookworm.
iv Mental hazards (e.g. shift work, constant danger).

1.6.1 Dust hazards in coal mining

Dust is the cause of the many of the cumulative health hazards in the coal industries, and is hence dealt with in some detail.

The main sources of dust in the mining operations are:

Point sources: (i) Ore and waste loading points in trucks, railroad cars, etc. (ii) Ore chutes in the haulage systems (bin, conveyors), (iii) Screens in outdoor crushing plants, (iv) Exhaust from dedusting installations, and (v) Dryer chimneys.

Dispersed sources: (i) Waste dumps, (ii) Ore stockpiles, (iii) Haul roads, (iv) Tailings disposal.

Dust is a serious hazard in coal mining. Coal and some stone dust are produced in the process of drilling, cutting, crushing and blasting of the coalface. The dust gets airborne due to ventilation, shoveling, transport and human movement. Only fine dust particles of diameter 0.5–5 μm are respirable. Anthracite (hard coal) particles are more hazardous than particles of soft coal (e.g. lignite).

Respirable coal particles pass through the upper airways, and finally settle down in the respiratory branchioli. There they accumulate and form nodules. Exposure to respirable coal dust over a period of years leads to the incidence of Coal workers' Pneumoconosis (CWP, also known as Anthracosis or Black Lung). X-ray examination is the principal method of diagnosing CWP. Simple CWP will not progress when once there is no more exposure to coal dust. But the complex CWP keeps on getting progressively more and more serious, leading to emphysema and heart failure.

The International Labour Organization (ILO), Geneva, has developed elaborate classifications for pneumoconiosis and silicosis, for clinical and epidemiological purposes. The characterization of the lung function is based on the parameters of Forced Vital Capacity (FVC) and Forced Expiratory Volume in one second (FEV1). If unchecked, the conglomerate silicosis may lead to emphysema and heart failure.

The composition of the dust (in terms of coal and silica particles) varies from mine to mine. Anthrcosilicosis is a mixed disease caused by the inhalation of both coal and silica dust. Simple anthrocosis may degenerate into Progressive Massive Fibrosis (PMF).

Workers suffering from silicosis become highly susceptible to the dreaded disease of tuberculosis. Such an infection is hard to treat, as the fibrous and scar tissues impede the penetration of antituberculostatica. No wonder that 25% of the silicosis deaths are attributable to silicotuberculosis.

Bronchitis among the mine workers is attributable to the inhalation of relatively coarse dust particles of the diameter 5–15 μm. Such particles are too large to go into the lungs. When inhaled, these particles get stuck in the upper airways. Constant irritation by such particles leads to infection, coughing and production of sputum.

Statistics show that in a number of countries one out 8 workers suffers from CWP and silicosis, and one out three workers suffer from bronchitis. In USA, during the period, 1970–77, Federal Black Lung Compensation was awarded to 420,000 coal mine workers who were totally disabled because of CWP. A survey during 1974–77 by the National Coal Board of U.K. found that about 7% of the British Coal Miners were suffering from CWP. It has been reported that the incidence of CWP in India may be as high as about 16%.

1.6.2 Dust hazards in steel industry

The steel industry is notorious for the large quantities of visible fumes and clouds of dust. The problem here is one of quantity of dust, rather than the toxicity of dust. Two categories of dusts can be recognized in the steel industry (UNEP, 1986, p. 36).

i Coarse particles (diam. 10–100 μm) produced in the course of mechanical operations, such as crushing, screening, and charging of raw materials – these settle down fairly rapidly.
ii Particulates (less than 1 μm diam.) produced in the course of high temperature metallurgical processes (such as, blast furnaces, steel making, oxygen scarfing). These remain suspended in air for long periods.

1.6.2.1 Pathological effects of mineral dusts

Toxic particles, such as silica, can cause severe fibrogenic reaction. In Industrialized countries, the incidence of pneumoconiosis has been kept under control by improved dust control techniques. In the Industrialized countries, asbestosis and pleuropulmonary cancer arising from exposure to asbestos particles in the construction materials have emerged as principal health hazard arising from mineral dusts. In USA, there have been cases of school buildings being completely demolished because asbestos products have been used in their construction.

Soot or carbon black, which is the waste product of incomplete combustion in private or industrial buildings and incinerators, is the most visible dust, although not necessarily the most harmful.

1.6.2.2 Fibrogenetic effects

The biological activity and hence the pathological effect of mineral dust particles depend upon the extent of their penetration, retention and clearance.

Some mineral particles, such as those of carbon, iron and barium, have limited biological effect. When inhaled in large quantities, they accumulate and cause pneumoconiosis around the terminal repository bronchioles. In the case of mixed dusts, the more the content of silica, the more pronounced is fibrosis.

Electron microscopic images (×300) allow us to distinguish between the interstitial fibrosis of the lung associated with pleural fibrosis, and the nodular or massive hyaline fibrosis found in silicosis. This may be a manifestation of the difference in the penetration and clearance of the two kinds of dusts.

It has been observed that fibrous particles lodged in the lung tend to be surrounded by a ferrous protein sheath. This probably represents an effort by the body to detoxify the toxic fibres.

1.6.2.3 Carcinogenic effects

Low-rank coals invariably contain pyrite. Arsenic may substitute in pyrite (FeS_2) or may be found in the form of a separate mineral, arsenopyrite (Fe As S). In Guizhou province of China, coals have very high arsenic content (9600 mg kg^{-1}). When such high-As coal is used for cooking, keeping warm, and drying of grain, arsenic content of the ambient kitchen air rises to 0.003–0.11 mg m^{-3}. Exposure to this environment leads to the absorption of arsenic by the respiratory tract, skin, and digestive tract (Zheng, B.S. et al., 1994, quoted by Sun, 1999).

Coal is the principal source of energy in China. China is the largest producer of coal in the world (2842 Mt in 2006). With increased industrialization, and with people aspiring for a higher standard of living, consumption of coal-fired thermal energy as also the use of coal in home heating, has been growing rapidly. There is a price for this. It has been said that twenty out of thirty most polluted cities in the world are in China, and one out of three deaths in China is due to contaminated air and water.

Two or more mineral substances may interact together, some times antagonistically, and more often synergistically. A possible mechanism for the operation of synergism is as follows: when the solid particles are lodged in the lung tissues, the adsoptive capacity of the solid particles allows them to retain the gaseous or soluble substances adsorbed on them. It is also possible that through their surface properties, the solid substances act as catalysts, accelerating or facilitating some processes. They may also serve as vectors of toxic substances, penetrating the cells more readily.

1.6.2.4 Analytical methods

As the mineral dust particles tend to have a size range of 1 mm to 1 μm, the usual practice is to study the individual particles for their size (which determines their aerodynamic properties, and determines whether they are respirable or not), shape (whether the particle is fibrous), mineralogy, chemical composition and speciation, isotopic characteristics, etc. At least two characteristics of a mineral dust particle, namely, morphology and chemistry, need to be determined.

1.6.2.5 Monitoring of dusts

Dust is monitored in the following ways:

i Air samples are regularly analysed for their dust content. Automatic air samplers at fixed locations analyse the air, and feed the information to the central control point. Besides, personal samplers worn by the workers are also analysed.

The Threshold Limit Values (TLV) for the total dust are 10 mg m^{-3}, for silica dust 0.2 mg m^{-3}, and for coal dust 2 mg m^{-3} (incidentally, this implies that the silica dust is ten times more hazardous than coal dust),

ii Workers must undergo regular medical checks (X-ray photographs of the lungs, lung-function tests, etc.), and records should be kept. Workers with dust-related illnesses may be shifted to dust-free jobs.

1.6.3 Falls and explosions

Most of the serious accidents in mining arise from falls from the roof or walls in the underground mining, and falls from side-walls in the opencast mining. The falls may seriously or fatally injure the workers, and may entomb and suffocate them.

Explosions constitute a serious hazard in mining. They may be caused in the following ways (i) poor timing and misfiring of charges in blasting, (ii) methane gas released by drilling and blasting may explode when it is mixed with air in a proportion of 5–15%, (iii) fine particles of coal dust may explode, following a methane gas explosion. Dust explosions have a multiplier effect – one explosion triggering another. The effects of these explosions are invariably very serious, and may consist of severe burns, asphyxiation, intoxication caused by carbon monoxide gas, pulmonary oedema, and physical injuries.

1.6.4 Mine flooding

Flooding of coal mines may cause hundreds of deaths, as has happened in the Damodar Valley coalfields in eastern India. If an underground mine is in the proximity of a river, and if the river and the coal mine are separated by a relatively porous rock, the water in the river may leak into the mine and flood it. Some times water from a flooded mine may leak into a nearby working mine. Such flooding can be avoided by the construction of underground grout barriers, called hydrocurtains.

1.6.5 Chemical hazards

Methane gas is easily the most serious chemical hazard in the underground mining of coal. It is naturally present in the layers of coal, and gets released when the layers are drilled through or blasted. It is non-toxic when inhaled. However, methane dilutes the oxygen in air, and thus causes oxygen deficiency, and asphyxiation. The symptoms of methane intoxication are nausea, unconsciousness and convulsions.

The principal hazard due to methane arises out of its high flammability, and the consequent ability to cause explosions. Hence great care has to be taken to ensure that there is no build up of the methane concentration in the air in the mine. It is necessary to check methane concentrations frequently using the methane detectors. As a rule, the methane concentrations should invariably be checked before and after drilling and blasting. Now-a-days, in the highly mechanized mines, the methane concentrations are routinely monitored using remote registration. Methane concentrations in the air should not exceed 0.5 to 1.0 vol. Percent.

Ventilation can be used to dilute the methane concentrations to safe levels. An innovative approach that is followed in some countries is to collect the methane gas from the mines, and use it as a fuel for boilers.

1.6.5.1 Health hazards due to chemical pollutants in air

Carbon monoxide is an odourless, highly toxic and extremely flammable gas. Incomplete combustion produces the gas, which is therefore to be found in the exhaust fumes of combustion engines and in methane or coal dust explosions. Carbon monoxide has 200 times more affinity than oxygen for haemoglobin in the blood, and hence causes acute intoxication of all body cells. The symptoms of carbon monoxide intoxication are headache, weakness and shortness of breath. If not treated promptly, carbon monoxide poisoning may result in collapse and death. Treatment consists of artificial respiration and supply of oxygen.

The level of carboxyhaemoglobin is linked not only to the concentration of carbon monoxide in the air, but also to the duration of exposure, the volume of air passing through lungs, and the blood volume circulation. In healthy individuals, carboxyhaemoglobin levels of 5% impair the vision, but in the case of individuals with heart or lung diseases, levels of 2.5% can be harmful. Hence the average atmospheric monoxide levels should not exceed 11.5 μg/m^3 (UNEP, 1986, p. 37).

Oxides of sulphur (SO_x)

Sulphur dioxide (SO_2) gas is a respiratory irritant. It causes respiratory diseases, particularly in the elderly people and in young children. The health effects of various levels of atmospheric concentration of SO_2 are summarized as follows:

At 2.1-mg/m^3, early reduction of pulmonary function occurs,
At 10 mg/m^3, the pungent odour becomes easily identifiable,
From 17–35 mg/m^3, irritation of the throat and nose occurs,
At 58 mg/m^3, it causes the irritation of the eyes.

At high concentrations, inhaled SO_2 causes the oedema of the larynx. SO_2 levels in the air should not exceed 24 hr. mean values of 0.10–0.15 mg/m^3, with approximately 50% of these values for annual mean exposure.

Sulphur dioxide concentrations in the air causes cankers in the flora, and corrodes the building materials.

Sulphur trioxide (SO_3) gets converted in the atmosphere to highly corrosive and toxic sulphuric acid. It is more toxic than SO_2 and affects the respiratory functions at levels of 0.35 mg/m^3. Oxides of sulphur become more harmful when combined with particulates.

Nitrogen oxides (NO and NO_2)

NO gets readily oxidized to NO_2 in the atmosphere, and therefore the consequences of NO_2 are more important. Nitrogen oxides are akin to carbon monoxide in that both are products of incomplete combustions, and are found in the same kinds of situations. At concentrations of 1.3 to 3.8 mg/m^3, respiratory functions are affected. Short term exposure (one hr.) to 47–140 mg/m^3 can cause bronchitis and pneumonia, and at 560–940 mg/m^3, fatal pulmonary oedema can occur. The guideline value is in the region of 0.19–0.32 mg/m^3. The intoxication by NO_2 may be treated preliminarily by the supply of oxygen, and antitussive medication.

Carbon dioxide is produced in the process of breathing. The inspiration (ambient) air contains 21% oxygen, and very little carbon dioxide. The expiration air contains 17% oxygen, and 4% carbon dioxide. If the ventilation is inadequate, i.e. there is no supply of fresh air, the percentage of oxygen in the ambient air gets reduced, while the percentage of carbon dioxide increases. If the oxygen concentration in the breathing air becomes less than 10–12%, a person becomes unconscious. This condition can be treated by administering oxygen.

1.6.6 Biological hazards

Biological hazards are those caused by living organisms. These tend to be common among the mine workers in the developing countries because of poor standards of hygiene and sanitation.

Tinea pedia is a fungus, which causes interdigital mycosis of the feet of the mine workers. The hot and moist climate of the tropical countries promotes the propagation of the fungus inside the boots. The fungus spreads by skin contact with infected waters in the shower rooms.

Coccidiodmycosis is a disease caused by the fungus, *coccidiodes inmitis*. The fungus can survive in the soil in a cyst form for many years. When the soil is exposed because of mining, the fungus may get released into the air. The inhalation of the spores may cause pulmonary symptoms, similar to tuberculosis.

Ankylostoma duodenalis is a disease caused by the parasite, hookworm. The victim develops hypochromic anaemia.

Weil's disease (leptospirosis *icterohaemorrhagica*) is spread by a bacillus in the urine of rats. The disease is marked by jaundice and internal haemorrhage. Workers may get exposed to this disease in mines, which use wooden props for roof support.

1.6.7 Mental hazards

A person working in an underground mine is always aware that falls of the ground, roof collapse, blasting and explosions of dust and gas, could injure or kill him any time. Such an environment may provoke feelings of anxiety, tension, irritability and fatigue. A person working alone in a mine may develop feelings of claustrophobia. If the management makes it known to the worker the various precautions that have been taken to provide security and comfort to him, the worker will feel less anxious, and more cheerful.

Almost always, the mines are operated on a shift basis (of, say, eight hours). The shift work has an adverse effect on the circadian rhythms of the body, leading to sleep disorders, stomach ailments and social stress. Some companies find that operation in 4-hr shifts, or 12-hr shifts on a 4-day rotation basis, may be less disruptive of the circadian rhythm.

1.7 THE WAY AHEAD

There are two areas where progress need to be made in order to address the problems arising from the use of coal: (i) How to generate more power from coal with reduced emissions, and (ii) How to address the problem of climate change using the currently available technologies.

1.7.1 Power generation technologies

The following account is largely drawn from "World Energy Outlook 2007", pp. 220–222.

Traditionally, coal-based power generation involved the combustion of pulverized or powdered coal to raise steam in the boilers. The efficiency of the process currently ranges between 30 to 40%, depending on the quality of coal, ambient conditions and the back-end cooling employed. A number of power-generation technologies are being developed which are characterized by higher thermal efficiencies, but also lower emissions of nitrogen oxides (NO_x) and sulphur dioxide (SO_2).

The most important new technologies are as follows:

1.7.1.1 Supercritical and ultra-supercritical pulverized coal combustion

Steam pressure and temperature largely determine the efficiency of the steam cycle. Most of the current plants use subcritical technologies which operate at 163 bar pressure and 538°C temperature. In the supercritical designs, the pressure used is typically 245 bars, and temperature of more than 550°C – under these conditions, water turns into steam without boiling. In the ultra-supercritical designs, the temperature used exceeds 600°C. Though such units need specialized materials for fabrication, and higher capital costs, their higher efficiencies make them cost-effective. Supercritical technologies have become the norm in OECD countries. China and India are building supercritical power stations. Japan, Germany and Denmark have commercial ultra-supercritical plants. Extensive R&D effort is ongoing to develop new kinds of materials, which allow efficiencies of more than 50%.

1.7.1.2 Circulating fluidized bed combustion (CFBC)

It is possible to design CFBC plants for a variety of coals and particle sizes. As coal is burned at low temperatures, less NO_x is produced compared with conventional pulverized coal (PC) boilers. Also, the operating temperatures are low enough for the *in situ* capture of SO_2. The efficiency of CFBC plants is similar to that of PC units. CFBC units that can be operated at supercritical mode are now available commercially. Poland is currently building the first supercritical CFBC plant (460 MW). CFBCs may not be practicable at ultra-supercritical plants, as the temperature of operation may exceed 550°C.

1.7.1.3 Integrated gasification combined-cycle (IGCC)

In this system, coal is gasified under pressure with air or oxygen to produce fuel gas which is then cleaned and burned in a gas turbine to produce power. Heat is recovered from the exhaust gas from the gas turbine, and is used to generate extra power. Efficiencies of the order of 41% have been achieved, and even higher efficiencies are possible with new gas turbine models. IGCC plants have been built in Europe, USA, China and Japan. The advantages of the IGCC plants are: (i) it is possible to control emissions as the gas clean-up takes place before the combustion of fuel gas,

Table 1.7.1 Potential wedges: Strategies available to reduce the carbon emission rate in 2064 by 1 Gt C/year.

Option	*Effort by 2054 for one wedge, relative to 14 Gt C/year BAU*	*Comments, issues*
Energy efficiency and Conservation		
Economy-wide carbon-intensity reduction (Emissions/$ GDP)	Increase reduction by addition of 0.15% per year	Can be tuned by carbon policy
1 Efficient vehicles	Increase fuel economy for 2 billion cars from 30 to 60 mpg	Car size, power
2 Reduced use of vehicles	Decrease car travel for 2 billion, 30 mpg cars from 10,000 to 5000 miles per year	Urban design, mass transit, telecommuting
3 Efficient buildings	Cut carbon emissions by one-fourth in buildings and appliances projected for 2054	Weak incentives
4 Efficient base load coal plants	Produce twice today's coal power output at 60% efficiency instead of 40% efficiency (compared to 32% efficiency today)	Advanced high-temperature materials
Fuel shift		
5 Gas baseload power for coal baseload power	Replace 1400 GW 50% coal plants with gas plants (four times the current production of gas-based power)	Competing demands for natural gas
CO_2 Capture and storage (CCS)		
6 Capture CO_2 at baseload power plant	Introduce CCS at 800 GW coal or 1600 GW natural gas (compared with 1060 GW coal in 1999)	Technology already in use for H_2 production
7 Capture CO_2 at H_2 plant	Introduce CCS at plants producing 250 Mt H_2/year from coal or 500 Mt H_2/year from natural gas (compared with 40 Mt H_2/year today from all sources)	H_2 safety, and infrastructure
8 Capture CO_2 at coal-to- synfuels plants	Introduce CCS at synfuels plants producing 30 million barrels a day from coal (200 times Sasol), if half of feedstock carbon is available for capture	Increased CO_2 emissions, if synfuels are produced without CCS.
Geological Storage	Create 3500 Sleipners*	Durable storage, success permitting
Nuclear fusion		
9 Nuclear power in place of coal power	Add 700 GW (twice the current capacity)	Nuclear proliferation, terrorism, waste
Renewable electricity and fuels		
10 Wind power for coal power	Add 2 million 1 MW-peak wind mills (50 times the current capacity) occupying 30 × 10^6 ha, on land or offshore	Multiple uses of land because windmills are widely spaced

(*Continued*)

Table 1.7.1 (*Continued*).

11 PV power for coal power	Add 2000 GW-peak PV (700 times the current capacity) on 2×10^6 ha	PV production cost
12 Wind H_2 in fuel-cell car for gasoline in hybrid car	Add 4 million 1 MW-peak windmills (100 times the current capacity)	H_2 safety, infrastructure
13 Biomass for fossil fuel	Add 100 times the current Brazil or US ethanol production, with the use of 250×10^6 ha (one-sixth of the world cropland)	Biodiversity, Competing land use
Forests and agricultural soils		
14 Reduced deforestation, plus reforestation, and new plantations	Decrease tropical deforestation to zero instead of 0.5 Gt C/year, and establish 300 Mha of new tree plantations (twice the current rate)	Land demands of agriculture, benefits to biodiversity from reduced deforestation
15 Conservation tillage	Apply to all cropland (10 times the current usage)	Reversibility, verification

* Sleipner project is located in offshore Norway. It began operations in 1996. CO_2 is separated from produced natural gas and injected into a saline aquifer. Over 1 Mt per year has been stored so far. It is expected that a total of 20 Mt will be stored in the project. There is extensive monitoring to track the dispersion of CO_2 in the aquifer, including the use of 4-D seismic techniques

Source: Pacala and Socolow, 2004, p. 970.

(ii) equipment needed is not too elaborate, and (iii) solid waste is in the form of vitrified slag. When CO_2 Capture and Storage (CCS) systems become operational, it would become a plus point for IGCC plant, as CO_2 capture from the IGCC plant is technically easier than from a conventional steam plant.

1.7.1.4 Other technologies

USA and Japan are in the process of developing a number of hybrid systems, such as integrated gasification – fuel cell, which combines a fuel cell with IGCC, and could achieve efficiencies of the order of 60%.

New technologies are being developed to make efficient use of low-grade coals, more efficient drying systems for high-moisture coals, ways of overcoming fouling problems in gasification and combustion, etc. In the case of CCS technologies, the purpose of R&D is to reduce costs and improve reliability.

1.7.2 Solving the climate problem with current technologies

A variety of mitigation technologies, such as, fusion, space-based solar electricity, artificial photosynthesis, have been suggested to combat the climate change. These revolutionary technologies, which need a vast R&D effort, are unlikely to become usable in the near future. As against this, Pacala and Socolow (2004) came with an innovative combination of largely proven technologies – on one hand they allow the meeting the world's energy needs over the next fifty years, while avoiding the damaging climate change by stabilizing the CO_2 in the atmosphere at 500 ± 50 ppm (i.e. less than double of the pre-industrial revolution CO_2 of 280 ppm).

In order to stabilize the CO_2 emissions at about 500 ppm, carbon emissions need to be held at the 2004 level of 7 Gt/y (25.7 Gt of CO_2 per year) for the next 50 years, even though under the Business-as-usual (BAU) dispensation, they are due to rise to 14 Gt/y by 2054. Seven wedges have been proposed to achieve reduction in carbon emissions. "A wedge represents an activity that reduces emissions to the atmosphere that starts at zero today and increases linearly until it accounts for 1Gt C/y of reduced carbon emissions in 50 years" (Pacala and Socolow, 2004, p. 968) (Table 1.7.1).

The importance of the paper by Pacala and Socolow (2004) arises from the fact that it indicates the various techno-socio-economic options open to countries to choose the "mix" that suit them best to achieve low-carbon economic growth. The single most important benefit of nuclear power is that no carbon dioxide (a green house gas) is emitted. The substitution of nuclear electricity for coal would reduce the CO_2 emissions by 92 Gt (giga tonnes or 10^9 tonnes) over 50 years, and would allow the CO_2 emissions to be stabilized at their current level of 25.6 Gt CO_2/yr (Pacala and Socolow, 2004).

Nicholas Stern, former Chief Economist of the World Bank, avers that the political challenge faced by the governments in regard to climate change is to achieve a low-carbon economic growth.

The 30 MW coal-fired power stations at Schwarze Pumpe in East Germany is among the first in the world to use the CCS technology. The oxy-fuel process involves the following steps:

i Air separation: Nitrogen removed from air. Stream of almost pure oxygen is pumped into boiler house,
ii Boiler House: Coal is burned in oxygen and recycled flue gas (water vapour and CO_2) producing heat to generate electricity,
iii Flue gas cleaning: Ash, sulphur and other particles are removed. The remaining gas is almost pure CO_2,
iv CO_2 compression: Gas is cooled and compressed to 1/500th of its original volume, producing liquid CO_2 which is held in storage tanks, and
v Tankers will transport liquid CO_2 to depleted gasfield for injection deep underground.

1.8 ROLE OF COAL IN THE ENERGY PORTFOLIO OF SOUTH AFRICA

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1.8.1 South African coal in the global setting

The critical importance of coal in the economy, particularly the energy economy, of South Africa should be evident from the following facts: South Africa has the sixth largest reserves (48,750 Mt) and is the fifth largest producer (244 Mt) and the fourth largest exporter (69 Mt) of hard coal in the world. Coal is the second most valuable mineral commodity, after platinum. Coal accounts for 93% of the electricity generation in South Africa.

South Africa has an experienced and efficient coal industrial complex and export industry. Its assets include a substantial infrastructure in place, large coal reserves and resources, a domestic market for more than 70% of production, and a solid reputation as a reliable exporter of consistently good quality low sulphur coal. Coal makes a major contribution to the country's economic and industrial development and has enabled South Africa to become almost self-sufficient in energy. South Africa lacks significant resources of natural oil and gas and imports crude oil to feed four internationally owned refineries with a combined capacity of 510,000 barrels per day.

Most of South Africa's coal is produced by eight mega-mines each producing more than 10 million tons per annum. These mines are owned by the five biggest companies, Anglo Coal, BHP-Billiton, Exxero (created in 2007 by the merger of Kumba Coal and Eyesizwe), Sasol and Xstrata, which produced 83% of the total output of 312 million tons in 2007. Coal provides: more than 25% of the country's liquid fuel needs via the conversion of coal to liquid fuels (CTL); 92% of electricity; a proportion of steel's coking coal; and most of the requirements of the metallurgical industry and domestic sectors. Coal has enabled State-owned utility Eskom to provide the lowest cost electricity in the world, a position it will likely retain despite the 53% real price increase in 2008. This has allowed for the growth of world-class competitive energy-intensive industries including smelters, refineries and downstream manufacturers of base metals, synthetic fuels and chemicals, steel, stainless steel, ferro-alloys, aluminium and aluminium products, and titanium slag and dioxide powders.

The outlook for growth in the coal sector is positive. The South African coal industry and Government (SAG) are gearing up to produce some 340 million tons of coal per year and adding the required infrastructure, respectively, to increase exports to Europe, Africa and the Middle East by some twenty million tons by 2012. Eskom is committed to adding 40,000 MW (20,000 MW of nuclear power) to the grid and doubling generating capacity to 80,000 GW by 2025, most of which will come from coal-fired plants. The oil-from-coal producer Sasol is to increase production from its existing plants by 20% – to nearly 200,000 barrels per day of crude equivalent – and is to build a new 80,000-barrel per day plant on the Waterberg coal field in the north-west of the country. This will increase Sasol's coal requirement from the current 40 million tons to about 70 million per year. By 2025, the coal industry could be called on to produce an additional 100 million tons of coal per year unless more use is made of nuclear, natural gas and renewable energy sources. Given its dependence on oil imports, the only viable alternative to coal for South Africa appears to be nuclear energy.

1.8.2 The South Africa energy scene

South Africa's primary energy mix is 68% coal, 18% oil, 9% biomass, 3% gas, 1% hydro and 1% nuclear. The 18% oil component includes 4% synfuels derived from coal conversion and is made up of 65% imported crude and 35% locally produced oil. South Africa's daily oil production is about 35,000 barrels of crude from three small off-shore oil fields; 160,000 barrels of crude equivalent from Sasol's two coal-to-liquid (CTL) plants; and 45,000 barrels of crude equivalent from State-owned PetroSA's gas-to-liquid (GTL) plant. South Africa imports some 430,000 barrels per day of crude at an annual cost of about $10 billion. In 2005, domestic oil production saved the country nearly $4.7 billion in foreign exchange.

Sasol's CTL process consumes about 43 million tons of coal per year, produced mainly from its own four mines, plus purchases from other collieries as required. South Africa's State-owned oil company Petro SA derives natural gas for its GTL plant from small gas fields off the south Cape coast. These are expected to reach end of life by about 2012. A major search is underway to replace this supply either by discovering more gas, importing liquid natural gas (LNG), or relocating the plant to the west coast where two offshore gas fields may be producing by 2012. The Sasol and Petro SA coal and gas conversion plants are the largest of their kind in the world.

Eskom generates 95% of South Africa's electricity and municipalities generate the remaining 5%. During 2005, 92% of Eskom's output of 273,000 GWh was from 10 coal-fired plants with a net maximum capacity of 32,680 MW.

Three others coal-fired plants with a total capacity of 3,540 MW will be returned to production by 2008. Apart from these base-load stations Eskom also operates a 1,800 MW pressurized water reactor (PWR) nuclear station at Koeberg in the Western Cape. Peaking and emergency supply is provided by two pump-storage stations totaling 1,400 MW and located in the Western Cape and KwaZulu/Natal, two gas turbine stations totaling 342 MW are in the Western and Eastern Cape provinces, and six small hydroelectric stations totaling 660 MW are located in various parts of the country. Eskom has obtained approval for the construction of three large coal-fired plants located on various coalfields of about 4,800 MW each; one is under construction, one in final planning, and a third under investigation.

Over the past decade, mainly due to the SAG's now defunct energy privatization program, there has been an under-investment in new coal-fired generation and transmission capacity. This became painfully apparent early in 2006 when an accident to Koeberg's Unit 1 generator caused the nuclear station to go off-line. The Western Cape suffered months of unplanned and (later) scheduled power outages due to a combination of insufficient generation and transmission capacity in and from Mpumalanga coal-fired power plants.

At the beginning of 2008 Eskom called *force majeure* on power supply to mines, industry and exports of electricity because of scheduled and unscheduled shut-downs of power stations, which nearly brought the whole national grid down. One of the reasons for this was the failure of supply from mines due to the exceptionally heavy summer rains. Pits were flooded and power station stockpiles were turned to mush, which could not be fed to the boilers. The SAG has since allocated some $50 billion to be spent over the next five years to boost the whole electricity system. This includes expanding base-load generation capacity from refurbished and new coal-fired plants and from standby gas/diesel-fired open cycle turbine plants. Nevertheless, reserve-generating capacity is likely to remain below 8% of usable capacity for the foreseeable future, less than the industry-recommended reserve of 15%.

The future of South Africa's international coal trade depends on a number of external factors including coal, oil and gas prices; concerns about energy security; competition from other energy sources and coal producers; and the ability to radically reduce emissions and capture and permanently store CO_2 gas at relatively low cost. South Africa is investigating a number of options and alliances to develop and implement clean coal technologies.

In 2005, five major and some 40 small coal companies produced 306 million tons of run-of-mine (ROM) coal from about 64 mines – 55% from underground operations. Over twenty of the smaller coal companies were created under Black Economic Empowerment (BEE) legislation and one is a black-owned and operated mine. The 245 million tons of saleable coal produced included 1–2 million tons of anthracite, coking and metallurgical coals, the rest being steam coal. Output came from Anglo Coal (23%), BHP-Billiton (22%), Sasol (20%), Exxaro (18%), Xstrata (8%), and small and BEE operators (9%).

1.8.3 South Africa's coal resources

South Africa has 19 principal coalfields spread over an area of some 700 km from north to south and 500 km from east to west (Fig. 1.8.1). SA coals are mainly high-ash bituminous and of Permian age. The northern fields (1–6) and the eastern fields (8, and 14–18) are generally of higher rank and contain 0% to 20% coking coals. The latter fields also contain the country's anthracite coals, which have mainly been mined out. The Central basin (rest) contains the bulk of the coal mined to date. They are high in ash and have to be beneficiated to provide export-quality, low-ash product. Some 60 billion tons of coal discards and fines lie on stockpiles where they create an environmental problem. Some of these are being reclaimed for burning in Eskom power stations.

The coals are generally high in ash and low in reactive constituents and have a low sulphur content of (generally) less than 1%. Nine coalfields host operating mines that produce predominantly thermal coals. The remaining fields are deep, of poor quality, may contain undesirable radioactive and trace elements, and are unlikely to be developed in the near future. However, some contain coking coals and Rio Tinto is currently evaluating the Limpopo field in the north of the country for this potential. There is no commercial production of coal-bed methane (CBM) but Sasol and Anglo American are investigating this potential in the Waterberg coalfield.

South Africa's estimated hard coal resource base exceeds 120 billion tons of which some 31 billion tons are considered to be reserves. (Note: Reserves are that portion of a deposit or resource-base that are economically recoverable under present economic and technical conditions.) The vast majority of this is steam coal, the remainder being anthracite and minor reserves of metallurgical and coking coals. In 2005, South Africa ranked fifth in production, and sixth in total reserves. However, because many countries do not comply with the reserve estimation standards used in South Africa, Canada and Australia, this ranking could change in the future.

The Waterberg field in the northwest hosts one mega-mine that produces 17 million tons of coal annually, of which 14.7 million tons feed the giant, dry-cooled, Matimba power plant (3,690 MW). Matimba is the largest dry-cool plant in the world. A second power plant of some 4,800 MW is under construction and should begin generating power by 2015. Officially the Waterberg contains 10% of South Africa's coal reserves but is estimated to host about 50% of the total resource base. The field extends westwards into Botswana where plans are being formulated to

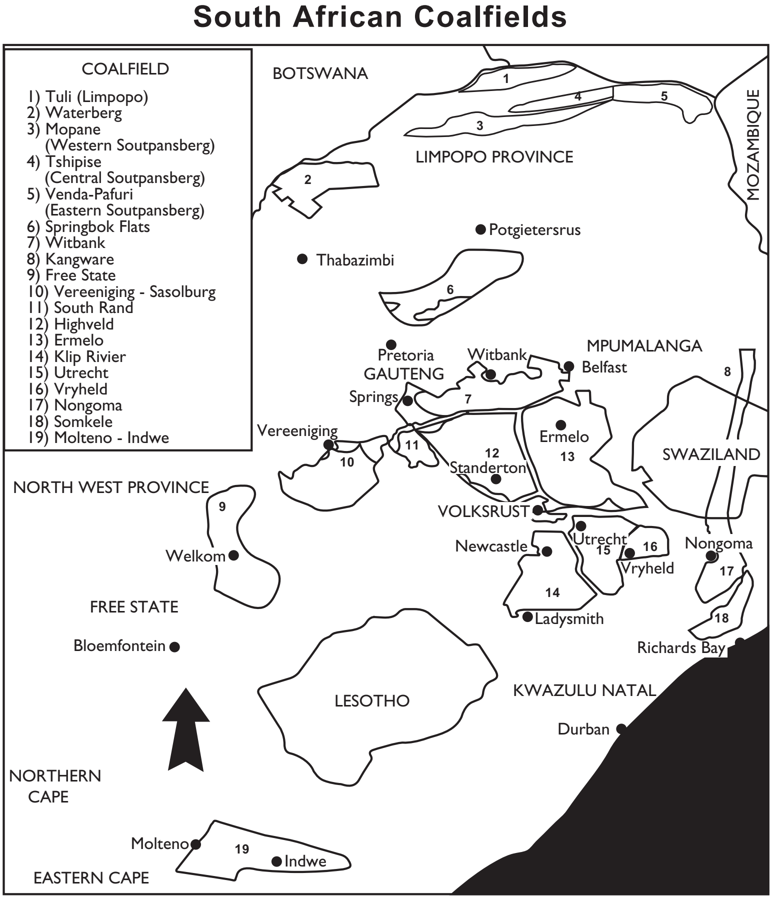

Figure 1.8.1 Coal fields of South Africa.

Source: White, this volume.

produce power for export to South Africa. Coal reserves by major fields in billions of tons are:

Coalfield	*Reserves*	*% Total*
Highveld	9.8	32
Witbank	9.4	31
Ermelo	4.4	14
Waterberg	3.1	10
Vereeniging/Sasolburg	1.8	6
South Rand	0.7	2
Soutspansberg	0.3	<1
Anthracite fields	1.3	4
Total	30.8	

Coal reserves are tied up in the Waterberg, which is under developed; a few large and many smaller undeveloped blocks of coal within the producing coal fields; and in remnant coal blocks and pillars left behind in old underground mines. Junior and black economic empowerment (BEE) operators mine some of the smaller and remnant blocks. Given favorable prices and markets and the on-going expansion of infrastructure, the industry estimates that it can build up to and maintain exports at 85–90 million tons per year for at least the next two decades.

South African coals contain a high percentage of non-carbon mineral matter and require processing in order to recover export quality coal. As a result some 60 million tons of discards and 4–8 million tons of duff (very fine coal) are generated annually and add to an existing waste stockpile estimated in excess of 1.2 billion tons. The duff coal is of export quality but difficult to handle without compaction. Some 75% of the discard coal is burnable in Eskom power plants but transportation costs are sufficiently high to discourage use. These products are now recognized as a significant resource and a number of projects are in progress for their exploitation. In the meantime these by-products are responsible for a considerable amount of the country's air and water pollution.

1.8.4 Coal export industry

Prior to 1975, the major coal users were Sasol (CTL plants) and Eskom (electricity generation). Coal exports were virtually zero. Once the decision was made to enter the international steam-coal market and infrastructure was put in place, the industry grew rapidly. A joint SAG-industry effort enabled the construction of a dedicated 580-km rail line to link the coalfields of Mpumalanga Province with the newly constructed coal stockyard, terminal, and port at Richards Bay on the KwaZulu/Natal coast – the Richards Bay Coal Terminal (RBCT).

In 2005, South African coal exports increased by 5% from 67.9 million tons in 2004 to 71.1 million tons, of which 69.9 million tons was thermal coal. However, this was 5% lower than the target rate of 74.8 million tons, due mainly to transport logistics and production problems. Of the tonnage exported, 77% went to Europe, 6% to the Middle East, 6% to the Far East, and the rest to South America and Africa. Small quantities of coal (less than 2 million tons) were exported through the Durban (BCT) and Maputo (MCT) coal terminals.

South African Coal Exports by Port in millions of tons:

Port	*2002*	*2003*	*2004*	*2005*
RBCT	66.0	68.3	65.9	69.2
Durban (BCT)	2.1	1.8	1.1	0.8
Maputo (MCT)	1.1	1.1	0.9	1.1
Total	69.2	71.2	67.9	71.1

The development of a coal export industry was a major boost for coal in South Africa. It resulted in the opening of a number of new collieries, particularly in the Witbank-Middleburg area, and stimulated exploration and development in other under-developed coalfields. It created a multi-billion dollar industry that currently produces over $3 billion annually in foreign exchange earnings. The result was the establishment of a major industrial hub and new city at Richards Bay, previously an impoverished fishing village.

New South African legislation, the Minerals Charter of 2002, requires that by 2014, 26% of the coal industry, and indeed the whole minerals industry, be owned and control by previously disadvantaged individuals and companies. Nineteen BEE companies have an exclusive export allocation of 4 million tons for 2006. This will increase to at least 14 million tons per year by the end of the decade when the export capacity expansion to 91 million tons per year (currently 72 million tons) is completed.

1.8.5 Infrastructure

South Africa's export coal rail and port infrastructure is owned and operated by government-owned corporations. The coal stockyard or RBCT is owned by industry. A combination of a lack of capacity within the government organizations and the opposition of labour unions to any form of privatization or contracting out of services has created major operational inefficiencies in the system. Consequently, the export target for 2005 was not achieved and that for 2006 could be as much as 5 to 10 million tons short of target based on performance to date.

Attempts to streamline operations and expand infrastructural capacity have been constrained by political, environmental and legal wrangles between government, labour and industry. Additionally, the inability of producers to provide coal to loading bays on schedule has exacerbated delays. Producers and the authorities appeared now to have reached an agreement to expand export facilities from 72 million tons to 91 million tons by the end of 2008, and to provide export opportunities for BEE producers.

In December, 2005, SAG-owned rail carrier Transnet Freight Rail (TFR) approved an investment of $4 billion to increase coal rail capacity by 30% in order to fully utilize additional space created by the RBCT expansion. The port expansion project is likely to go ahead in two or more phases, as environmental and lease negotiations are concluded. Whether the RBCT will meet its 2008 export target remains in doubt. Expansions are also planned for the Durban and Maputo ports. Currently, 95% of coal exports pass through Richards Bay.

Export coal capacity through the RBCT is, in general, proportional to the equity held by its shareholders. Three major shareholders Anglo Coal, BHP-Billiton and Xstrata, hold 86% of the equity and export allocations. This has constrained entry by other potential exporters, particularly the new BEE producers, and a license to expand the terminal was withheld for nearly a decade pending BEE companies being allocated export capacity. The current situation in million tons per year (Mtpy) is:

Company	*Production (Mtpy)*	*share%*	*RBCT allocation*	*Export (Mtpy)*
BHP-Billiton	54	22	37.4	27.0
Anglo Coal	57	23	27.5	19.8
Sasol	48	20	5.0	3.6
Eyesizwe (BEE)	26	11	1.2	0.9
Kumba (now BEE)	20	8	–	–
Xstrata	19	8	20.9	15.1
Total SA	4	2	5.7	4.1
Kangra	3	1	2.3	1.7
Other BEE/Juniors*	14	5	–	–
Total	245			72.0

* BEE companies had a 4 million ton allocation for 2006.

BEE conditions for the RBCT Expansion to 91 million tons per year:

In 2005, the Mozambique Matola Coal Terminal (MCT) exported 1.15 million tons of South African coal, against a target of 1.4 million tons. The MCT has set a target of between 1.4 million tons and 1.5 million tons for 2006, which is dependent on rehabilitation of the Witbank-Maputo rail line and the supply of larger wagons. Durban's Bulk Connections Terminal (BCT) is estimated to have loaded only 750,000 tons during the year against a target of 1.4 million tons, mainly due to an eight-month upgrade of the facility. BCT has bought new equipment to improve shiploading rates to make the terminal a more viable option in 2006.

1.8.6 The value of coal in South African economy

During 2005, coal became South Africa's second most valuable commodity, after platinum, in terms of total sales. Coal generated revenues of $5.6 billion of which $3.2 billion represented export earnings. Coal also generated $1.5 billion from coal-derived chemical exports. The industry directly employed 52,000 people and paid over $1 billion in wages. The Chamber of Mines estimated that coal was responsible for a further 165,000 jobs in related support industries and, in the South African social context, an additional 1.5 million people (4% of the population) owed their livelihood to coal.

Coal provides 25% of the country's liquid fuel needs, 92% of electricity production, a proportion of steel's coking coal, and most of the requirements of the metallurgical industry and domestic sectors. Coal has enabled Eskom to provide the lowest cost electricity in the world (36% less than the next cheapest producer, Canada). This, in turn, has allowed for the growth of world-class competitive energy-intensive industries including metal smelters and refineries and the downstream manufacture of base metals, synthetic fuels and chemicals, steel, stainless steel, ferro-alloys, aluminum and aluminum products, and titanium slag and dioxide powders – South Africa is the world's major producer of ferro-chrome, -manganese, and -vanadium.

Including linkages, coal is, arguably, the country's most valuable and strategically important mineral commodity. Coal makes major contributions to energy security, employment, revenue generation, export earnings, industrial development, import substitution, and socio-economic development and welfare. In 2005, in addition to export revenues, 175 million tons of coal was used locally to generate a net 273,400 GWh of electricity, produce 55 million barrels of synfuels, and manufacture a wide variety of carbon-based chemicals for export. In total, the value of coal to the South African economy exceeded $20 billion.

In light of Eskom's critical need to expand generation capacity, the next seven years should see five or six coal-fired plants come on stream. Three mothballed plants with a total capacity of 3,540 MW are currently being brought back into service. A new 4,800 MW plant is under construction on the Waterberg field and another 4,800 MW plant is planned for the Highveld field in Mpumalanga Province. A third new 4,800 MW plant is currently being evaluated for an as-yet-to-be announced location. Mines in the regions are planning to increase output of both steam and export coals and a number of new mines have been opened or are in the development stage of preparing to cater for the pending upsurge in demand. Infrastructural plans include expansions to the RBCT and to the CoalLink line that feeds the terminal and to the upgrading of the rail link to the Grootegeluk mine. In addition plans are being laid by CIC Resources (Canadian) for establishing a new mine and power station on Botswana's Mmamabula coalfield, which is the western extension of the Waterberg coalfield which hosts South Africa's largest coal operation and the world's largest coal beneficiation complex. Most of the power would be exported to South Africa.

Other coal companies intend expanding production to feed planned new Eskom power plants. Rio Tinto is exploring the coking and steam coal potential of the Limpopo coalfield, and a number of projects are underway to provide export coal for the RBCT expansion. The coal industry is confident that it can supply an additional 100 million tons of coal per year for export and to meet the future needs of Eskom and Sasol. However, there is concern that South Africa's rapidly diminishing reserves of higher quality coal may not be able to sustain exports of 91 million tons per year for any length of time. Much reliance is being placed on new BEE and smaller producers to fill the production gap, and on technology to upgrade coal for export.

1.8.8 Clean coal technologies

More stringent controls on all forms of coal pollution are inevitable. Eskom's Executive Manager has stated that any new coal plants will have to be based on state-of-the-art clean-coal technology and improved efficiency to ensure that less CO_2 is emitted per unit of production. Established carbon capture and storage (CCS) technology is not yet economically viable and requires about 40% of the energy produced just to remove CO_2. Major producers and users of coal, including Anglo Coal, BHP-Billiton and Eskom, were participating in the United States' FutureGen project, which had as its goal the development and construction of a zero emissions coal-based power plant, and which was aborted earlier this year in favour of a different (yet to be defined) approach to funding clean coal technology. South Africa is still committed to this goal.

In the meantime, best-practice clean coal technologies, processes and operations are being evaluated. Eskom is operating an experimental in-situ underground coal gasification project at the Majuba colliery and is investigating the viabilities of coal-bed methane (CBM), fluidized bed combustion (FBC), combined cycle gas turbine (CCGT) generation, pressurized boilers, identifying sites for future CO_2 storage, and other developed and developing technologies. An immediate goal for Eskom is the management of supply and demand and the efficient use of electricity, which it claims will save the construction of a 3,600 MW plant over a ten-year period.

1.8.9 Legislation and policy

Since the ANC-dominated government was elected in 1994 it has enacted legislation aimed at transforming the South African labour market and public and private sectors. This includes a host of general labour, equity, affirmative action and economic empowerment legislation aimed at propelling historically disadvantaged South Africans (HDSA) into the formal economy. Specifically provided for are: improved working conditions; upgrading skills; advantageous access to employment opportunities; and participation at all levels in the economy. (Note: The South African Constitution includes all women in the category of HDSA. However, in practice white women are excluded from this category.)

The minerals industry being South Africa's most important economic sector was the first target of the SAG for transformation and empowerment. The government's aim was and is to enable (initially through legislation) HDSA to play an increasing role in all aspects of the minerals sector, from which they were effectively excluded under apartheid legislation. Transformation was to be accomplished through The Mineral and Petroleum Resources Development Act (Minerals Act) and its appendages, namely the Black Economic Empowerment (BEE) Charter (Mining Charter) – both took effect in May and August, respectively, of 2004. These were followed by a number of bills, including the Royalty Bill and the Beneficiation Bill that are still under consideration. (Note: The term HDSA has, in general, given way to BEE, meaning "black people", the generic term for indigenous Africans.)

The Liquid Fuels Charter (LFC) of 2000 was the first of many industry sector charters. It covered the oil industry from production and transportation to refining, retailing, skills development and procurement. Its main tenet was for 25% of equity and management control of all South African liquid fuel entities to be in the hands of black companies within 10 years (by 2010) and that the industry should facilitate the financing of such deals. In addition, the LFC required that a minimum of 25% of procurement expenditure be earmarked for BEE suppliers. It also stipulated that: BEE investment should be broad-based and for the long-term; deals should take place at market value; quality and standards should not be compromised; and BEE partners should add value to the undertaking. (Comment: To date, many BEE deals have not met these criteria.)

The Minerals Act and the Mining Charter, both now in force, and the Royalty and Beneficiation bills that are still to be finalized, followed the LFC. The Act and Charter require that 15% of a company's South African assets, as measured by equity, production, management control or other, as spelt out in a "score card", must be in the hands of black people by 2009 and that this be increased to 25% by 2014. The industry was also tasked with facilitating financing of BEE deals by up to $15 billion to 2009 and a similar amount to 2014.

The most confrontational aspect of the legislation was (initially) its focus on the transfer of mineral rights to state custodianship. The current areas of contention are the Royalty and Beneficiation bills. The early royalty discussion document proposed a 2% assessment on gross revenues for coal. The Beneficiation Bill is set to propose a minimum level of product upgrading before export. If not attained, the exporter could be required to pay some form of export duty. At time of writing neither bill had been finalized for public comment.

Given, that strategies to meet black empowerment targets have been implemented by the major coal companies throughout the past four years, the structure and productivity of the coal industry has remained largely unchanged. Currently, nineteen BEE coal companies have been allocated export entitlements through the RBCT, own more than 20% of coal production and, pending completion of BEE deals; Exxaro Resources could leap-frog Anglo Coal to become the biggest producer of coal in South Africa.

1.8.10 Opportunities for South African coal

Sustained high prices for export coal, up some 200% since 2003, and the continuing growth of the domestic economy, have been good for all producers. Additional opportunities for coal could come from increased tonnage requirements from Eskom for its expanding coal-fired plants; increased coal exports to Europe and the rapidly growing economies of the Far East; as well as the possibility of additional coal-to-liquid (CTL) plants in South Africa. Because of the significant advantages of coal to the South African economy, the SAG has stated that coal will continue its dominant role as an energy source for at least the next four decades. This should provide industry stability and the opportunity to research and develop other forms of energy for transportation and to power industry.

1.8.10.1 Threats to South African coal industry

The expansion of coal exports will depend on a number of factors outside the control of South African producers. Exports to the EU countries, which accounted for 77% of total exports in 2005, will depend on Europe's resolve to reduce the use of coal to combat climate change concerns versus cost considerations should oil prices continue to escalate. Germany and Poland remain heavily dependent on coal while Italy is converting some oil-fired plants to coal and British Coal's plan to reopen a colliery in South Yorkshire and to build a $1.5 billion power plant equipped with technology to capture and store carbon dioxide.

A further threat to South African coal exports is the EU Commission's proposed new regulatory framework for the Registration, Evaluation and Authorization of Chemicals (REACH). If implemented as is, the regulations would effectively embargo the import of raw and processed products containing any form of toxic or polluting elements, and could include coal. However, given current concerns regarding energy supply security, it seems that the EU will continue to use coal and is likely to employ clean coal technology (CCT) to control emissions.

Major competition to South African coal exports is likely from Australia, Colombia and Indonesia, which produce higher quality steam coals. Nuclear power plants are also a competitive threat, given uranium's geographically-friendly distribution – South Africa, Canada and Australia – and its minimal emissions. However, the current general distrust of anything nuclear could retard further development of nuclear energy.

While alternative and renewable energy forms may pose a threat to coal (and other fossil fuels) in the future, mainly for off-grid power and as a supplement to liquid fuels, the South African focus is likely to be on developing clean coal technology and on commercializing the mini-nuclear power – such as, Pebble Bed Modular Reactor (PBMR), scheduled for production from 2013 onwards – a prototype has yet to be constructed.

1.8.10.2 Projected developments in the energy sector

South Africa's power generation facilities are looking at new technologies that are installed elsewhere but not yet locally. These include:

Fluidized bed combustion
Combined cycle gas turbines
Super-critical boiler systems
Conventional PWR nuclear reactors
PBMR
In-situ coal gasification

Carbon capture and storage – currently developing an "Atlas" of possible geological storage sites in South Africa. The country has no major oil or gas reservoirs so is looking at our extensive coal measures and dolomite formations for storage. Other clean coal technologies to capture NO_X, SO_X, CO_2 and organic emissions use conventional, but very expensive gas desulphuriser units.

SASOL CTL plants are planning to make more use of natural gas from Mozambique in the processes, particularly for expansions and for their planned conversion plant.

Many of the technologies are too expensive to retrofit on older plants, but proposed legislations will require all new coal-fired plants to be CO_2 "capture ready" in anticipation that CCS technology will be proven in the future.

1.9 ROLE OF COAL IN THE ENERGY PORTFOLIO OF CHINA*

U. Aswathanarayana

1.9.1 Demographic, economic and political context

China with 1.31 billion people (which is one-fifth of the global total) is the most populous nation in the world. The population is expected to increase to only 1.46 billion by 2030, because of the strictly enforced one-child policy. Economic growth has been driven by industrialization, with industry accounting for about 50% of the GDP. China has emerged as the largest producer and consumer in the world of several commodities, including iron and steel, cement and ammonia. The GDP of China has been growing at a phenomenal rate of 9.8% per annum since 1980 – it reached 11% in 2006, and the first half of 2007. In 2006, China achieved the gross GDP of USD 10 trillion (10^{12}), which is 15% of the global GDP. The Chinese economy has become second in the world, in terms of the Purchasing Power Parity (PPP), and the fourth in the world in terms of market exchange rates. The Per capita GDP, however, is low and is about one-fourth of the OECD average in terms of PPP. India comes closest to China in terms of population and coal resources (Aswathanarayana, 2008).

1.9.2 China's energy sector

In a matter of a generation (1980–2005), China has become the world's fastest growing energy consumer. During the period, 1980–1995, China was able to meet its rapidly increasing needs from its domestic resources. The picture changed drastically during the last decade. China became a major global player in the energy markets, and has been vigorously acquiring energy properties (particularly, oil) in many countries.

The sector-wise Total Primary Energy Demand in China in 2005 (1742 Mtoe- Million tonnes of oil equivalent) is as follows: Coal (62.8%), Oil (18.8%), Gas (2.45%),

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* The chapter draws extensively from "*World Energy Outlook 2007*", which has special focus on China and India, issued by the International Energy Agency, Paris.

Nuclear (0.8%), Hydro (2.0%), Biomass (13%), Other Renewables (0.2%). Thus, the Renewable sources constitute about 15% of the Total Energy Demand. Coal is used for power generation (55%), Industry (26%), Residential (4%), others (such as, transport, agriculture, non-specified).

Table 1.9.1 lists the key energy indicators of China.

1.9.3 Coal resources of China

China ranks next to Russia in terms of coal resources. China has 1003 billion tonnes based on exploration and mapping, with proven reserves of 192 billion tonnes (latest figure). Sustained efforts are under way to prove more resources. Figure 1.9.1 gives the distribution of the coal fields in China (source: Beijing HL Consultant, 2006). The major resources of coal lie in northwest China, in the provinces of Shanxi, Inner Mongolia, Shaanxi, Xinjiang, Ningxia, Hebei, Gansu, and Qinghai. Shanxi is by far the richest coal area, with 26 billion tonnes of coal which constitute 38% of China's coal resources. The coastal areas have only 6% of coal resources. As against this distribution of coal deposits, the major demand centers for coal are in the industrialized east and southeast.

This situation necessitates the transport of coal over long distances, causing a heavy burden on the railways and high transportation costs.

As is well known, the older the coal, the higher would be its rank. The Permo-Carboniferous coals of China are of high grade – anthracitic or bituminous, medium volatile, coking coals. Ash content is highly variable (20–40%), and so is the sulphur content (1–5% or more). About 60% of the coal deposits of China are of Jurassic age. These are essentially good quality steam coals, with high volatiles, low ash (5–10%) and low sulphur (less than 1%) contents (Barlow Jonker, 2005). Most of the coal deposits in China are located at depth, and hence opencast mining is

Table 1.9.1 Key energy indicators of China.

	1980	*1990*	*2000*	*2005*
Total Primary Energy Demand (Mtoe)	604	874	1121	1742
Oil demand (mb/d)	1.9	2.4	4.7	6.7
Coal demand (Mtce)	447	763	899	1563
Gas demand (bcm)	14.3	15.3	27.3	50.6
Biomass and waste demand (Mtoe)	180	201	214	227
Electricity output (TWh)	313	650	1387	2544
Primary Energy Demand/GDP (index 2005 = 100)	342	207	101	100
Primary Energy Demand per capita (toe per person)	0.6	0.8	0.9	1.3
Oil imports (mb/d)*	–0.2	–0.4	1.4	3.1
Electricity demand (kWh) per capita	318	570	1093	1940
Energy-related CO_2 emissions (Gt)	1.4	2.2	3.3	5.1

* Negative numbers denote exports.

Mtoe = Million tonnes of oil equivalent; mb/d = Million barrels per day; Mtce = Million tonnes of coal equivalent; bcm = Billion cubic metres; TWh = Terawatt hours (Terra = 10^{12}); kWh = kilowatt-hour; Gt (Gigatonnes) (Giga = 10^9).

Source: "World Energy Outlook, 2007", p. 263.

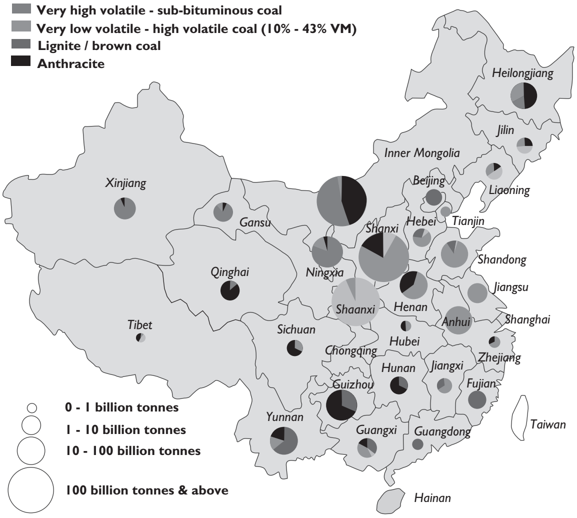

Figure 1.9.1 Location of China's coal resources (See colour plate 1).

Source: Beijing HL Consultant, 2006.

generally not possible. Although the sulphur content of coal mined today is low to medium, it has been found that the sulphur content increases with depth in the coal deposits of north China. This could mean that high sulphur contents may emerge as a problem as deeper deposits are mined. Ash content may also increase with depth, making washing more expensive. The average calorific value of coal in China is 5400 kcal/kg, as against 6000 kcal/kg of internationally traded coals, but is better than of India's coal (4500 kcal/kg) and comparable to that of USA (5600 kcal/kg).

Coal production in China has increased more than five-fold during the last 27 years – from less than 0.5 b.t. in 1980 to more than 2.8 b.t. in 2007. The production of steam coal which accounts for about 90% of the total coal production is expected to increase at a faster rate than coking coal. Shaanxi province will continue to be the most important producer of coal, with increasing output from Mongolia, Shaanxi, Ningxia, and Guizhou provinces. The production from the coastal provinces will continue to be small.

The projected coal production upto 2030 is shown in Table 1.9.2.

The achievement of the projected coal production of 3334 Mtce by 2030 depends upon the restructuring and modernization of coal industry. The average productivity of 500 tonnes per man-year in China is low. There are about 20,000 small mines in which coal is produced manually, and in these cases, the productivity is as low as 100 tonnes per man-year. Despite their significant contribution to the coal production in China, these small, so-called Township and Village Coal Mines (TVCM) are not an unmixed blessing. Their extraction rate of 15% is very low, and thus the country loses substantial quantities of the unextracted coal forever. It is dangerous to work in these mines.

Most of the coal mining fatalities (~6000 per annum) in China occur in these mines. The extent of coal mining fatalities in China (2.04 deaths per million tonnes of

Table 1.9.2 Projected coal production by type, rank and region in China (in Mtce).

	2005	*2015*	*2030*
Coastal			
Steam coal	238	259	308
Coking coal	12	11	16
Inland			
Steam coal	1142	1978	2633
Coking coal	244	356	380
Total			
Steam coal	1380	2238	2939
Coking coal	256	366	395
All coal	**1636**	**2604**	**3334**

Source: "World Energy Outlook, 2007", p. 337.

coal, in 2006) is much higher than the figure of 0.03 in USA and 0.24 in India. The Government of China wants to reduce the TVCM mines to 10,000 by 2010.

In contrast, productivity is as high as 30,000 tonnes per man-year in the highly mechanized underground mines on the border of Shaanxi and Inner Mongolia which are operated by the Shenhua Group. Five mines, Daliuta, Bulianta, Yujialiang, Kangjiatan and Shangwan, with an annual output of 10 million tonnes each, are rated as among the most productive in the world. Bulianta mine has achieved the distinction of producing 20 million tonnes in a single year. The Yujialiang mine has installed longwall mining equipment involving a 413-metre coal face, the world's widest, with which to cut panels of coal upto 6000 m long (Chadwick, 2007).

In order to enhance the output and reduce hazards in the coal industry, the Government of China has taken a number of policy decisions: (i) Coal will be one of the sectors which would remain largely under state control, (ii) raise the productivity of mines through greater mechanization, and improve recovery rate from 46% in 2005 to 50% in 2010, (iii) establish six to eight large coal mining companies with an output of 100 Mt or more per annum, and eight to ten mines with an output of around 50 Mt, each, in the states of Shanxi, Shaanxi, Inner Mongolia and Ningxia. It is expected that by 2010, large and medium-sized mines would account for 75% of the coal production. NDRC (National Development and Reform Commission) announced in Oct. 2006 that hence forth, only mines which can produce more than 300 000 tonnes per annum will be given licence. By 2011, new mines are expected to produce 829 Mt per annum. The role model for the new developments is the Shenhua Group, a vertically integrated company, which achieved very high level of productivity through employing modern corporate management methods.

1.9.4 Coal transport

There is a mismatch between the natural distribution of coal deposits and location of the coal-using industries. About 55% of coal is used for electricity generation.

Where possible, electricity is generated in the pithead thermal power stations and transmitted. Coal which is used in industry (e.g. iron and steel, cement, fertilizer) (26%), residential (4%) and other purposes (15%), is transported by rail, road, inland waterways and coastal vessels. A billion tonnes of coal, which is roughly half of coal supply, is moved by rail. Older trains which have payloads of about 3000 tonnes of coal, still carry most of the coal. A recent, major development has been the building of dedicated rail links – the 600-km Daqion line, and 588-km Shuozhou to Huanghua line, which are efficient and can carry trains with payloads of 25,000 tonnes. The rail capacity is being extended through the construction of the Houma – Yueshan link in Shanxi, and the 740-km dedicated link from Baotou (in Inner Mongolia) to the port at Tangshan. By 2020, the length of the rail network is expected to reach 100,000 km, with separate long-distance lines for passenger and freight traffic.

The rail freight costs in China on the important west – east routes (0.12 yuan/tonne-km, eq. USD 0.016/tonne-km) are high by international standards. Coastal shipping involves handysize (about 30,000 dwt) vessels. China's ports, notably Qinhuaangdao, Shanghai and Guangzhou, handled 370 million tonnes of coal in 2005. China is engaged in the rapid expansion of port capacity. Smaller quantities of coal from some mines are transported in barges through stretches of the Yellow River, Yangtze River and Grand Canal. Large trucks of 60–80 tonne capacity are used to transport coal from some mines in Inner Mongolia and Shanxi. Trucks with a capacity of 20 tonnes continue to be used in a big way for transporting coal for distances upto 300 km, even though the transport costs are very high (0.5–0.8 yuan/line-km or USD 0.067–0.107/line-km).

Till recently, the Government controlled the coal prices. The position changed profoundly after China joined WTO. The FOB cost of coal from Shenhua's mines (including rail transport to Qinhuangdao port, and port loading and taxes) is about USD 30/tonne, which makes the Chinese coal highly competitive (for instance, the Asian marker price is about USD 75/tonne). With the Chinese Government promoting efficient mining companies, such as Shenhua, the indigenously produced coal is expected to be competitive in the short and medium term. Significant problems are, however, expected to arise in the long term. About 60% of the Chinese coal occurs at depths of more than 1000 metres, pushing up the costs of recovery with deeper mining. Under these circumstances, coastal areas in the south and east may find it more economical to import coal from Australia, Vietnam and Indonesia, than getting coal from deep, inland mines.

Despite the projected growth in the demand for coking coal during 2015–2030, China has enough resources of coking coal to meet its coking coal needs. China will export coal to countries like Korea and Japan which are closer to large coal export terminals, while importing coal from Indonesia, Australia, South Africa, etc. to meet the demand of coastal areas in the south.

1.9.5 Electricity from coal-fired power stations

In terms of electricity production, China ranks next only to USA. In 2005, coal-fired generation of electricity accounted for 78% of the total electricity supply. This level of share of coal-fired electricity is among the highest in the world, exceeded only by a few countries, such as Australia, South Africa and Poland. The installed capacity of coal-fired, power stations in China is 517 GW. Coal-fired, total electricity generation is 2544 TWh in 2005. Despite the rapid growth of electricity generation, the supply did not keep pace with demand, and power shortages were frequent during 2002–2005. The situation has eased since 2006 due to the addition of ~100 GW of power generation. The total generation of power is expected to increase by 4.9% annually, reaching 8472 TWh by 2030 (incidentally, this figure is comparable to the current level of power production of OECD North America and Europe combined!).

China is greatly expanding the use of pulverized coal with supercritical steam cycle technology. Though the supercritical technology is costly, it brings in two very significant benefits – higher efficiency and lower carbon emissions (Table 1.9.3).

China has now 30 GW of supercritical units, including 18 GW of supercritical plants installed in 2006. About 100 GW of supercritical plants are on order. Due to these technological innovations, the overall efficiency of coal-fired power generation is expected in increase from 32% in 2005 to 39% in 2030. The contribution of oil to power generation in China is small (2.4% in 2005), and this is expected to go down to 1% in 2030. Due to high gas prices, gas-fired power stations are confined to coastal areas. The installed capacity of nuclear power is 6.6 GW in 2005. The Government has the ambitious target of increasing the installed capacity of nuclear power to 40 GW by 2020. But because of the current global bottlenecks in the manufacture of reactor components, the chances are that the installed capacity of nuclear power may reach only 21 GW in 2020 and 31 GW in 2030. Electricity from nuclear power is 53 GWh (or 2.1% of the country's total electricity). It is expected to increase five-fold by 2030. China is the largest producer of hydroelectricity in the world. It produced

Table 1.9.3 Economics of coal-based power generating technology.

Technologies	*Availability of technology*	*Cost ($/kW)*	*Efficiency (%)*	*Market share in China*
Subcritical		500–600	30–36%	Most of China's current generating units are of this type
Supercritical	Available now	600–900	41%*	About half of the new units on order are of this type.
Ultra-supercritical	Available now, but needs further R&D. to increase efficiency	600–900	43%*	Two 1000 MW units of this type are under operation
IGCC (Integrated Gasification Combined Cycle)	Available now, but costs are high, and needs more R&D to increase efficiency	1100–1400	45–55%	Twelve units are planned, and are awaiting clearance by NDRC

* indicates current efficiency. Improved efficiencies are expected in the future.

Source: "World Energy Outlook, 2007", p. 345.

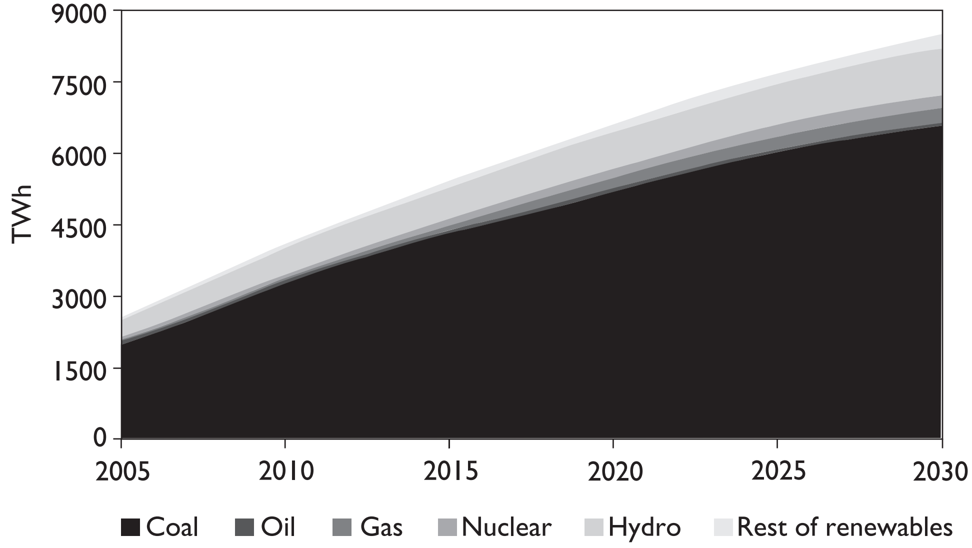

Figure 1.9.2 Projected electricity generation in China, 2005–2030 (See colour plate 2).

Source: World Energy Outlook, 2007, p. 345.

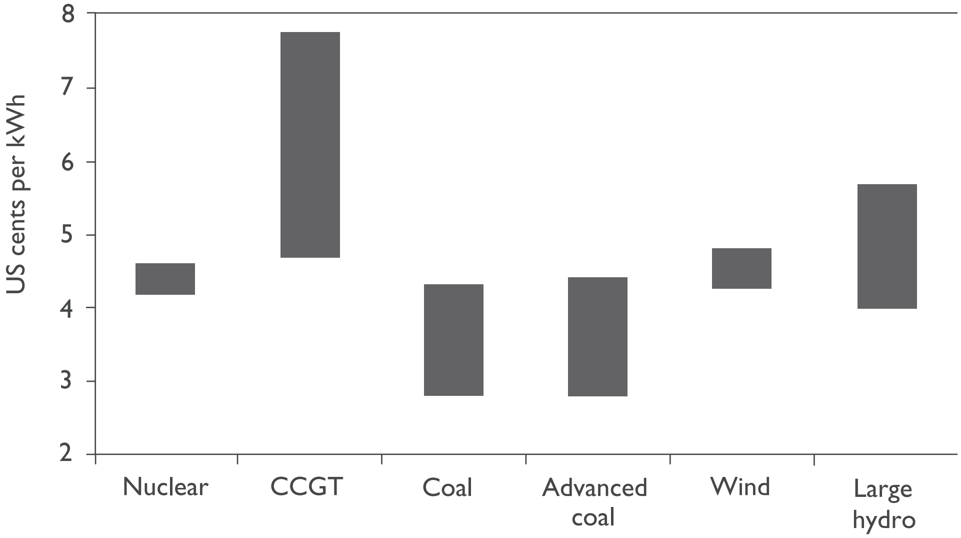

Figure 1.9.3 Shows the power generating costs of different types of power generation.

Source: "World Energy Outlook 2007", p. 353; CGCT = Combined Cycle Gas Turbine.

in 397 TWh in 2005, which is expected to rise to 1005 TWh in 2030. Combined Heat and Power (CHP) generation accounts for about 11% of total generating capacity. This is a dual-purpose activity – electricity, with heat being used for industrial and domestic heating. The power generation from CHP plants is expected to reach 611 TWh in 2030.

Figure 1.9.2 shows the projected pattern of energy generation in China during 2005–2030 (source: "World Energy Outlook, 2007" p. 345). Evidently coal will be the predominant source of power for a long time to come.

1.9.6 Economics of power generation

The cost of a particular pathway of power generation depends upon fuel price, capital cost, capacity factor and discount rates. If the implications of CO_2 emissions are ignored, coal is the cheapest source of electricity (US cents 2.8 per kWh). The construction cost of a nuclear power plant ($1500–1800/kW) is generally more than double the construction cost of a supercritical power station ($600–900/kW). In the case of China, the construction cost of nuclear power plant varies from $1769/kW for Quinshan III-1 to $2069/kW in the case of Daya Bay plant.

China needs to invest $150 billion per year, during the period 2006–2030. The total Investment in the energy sector is estimated to be $3.7 trillion (in year-2006 dollars). Out of this, 74% is needed for electricity (power generation, transmission and distribution), 15% for oil (Coal-to-Liquids, Refining, upstream), 7% for coal (mining, port), and 4% for gas (Upstream, LNG – Liquified Natural Gas, transmission and distribution).

1.9.7 Environmental impact of the coal industry

Environmental pollution is a serious problem facing China. According to the World Bank (2007), 20 out of 30 most polluted cities are in China, and costs of air pollution account for 3%–7% of GDP. The cost of health damage due to air pollution may reach 13% of GDP by 2020, under the business-as-usual scenario. Coal-fired plants provide 78% of the electricity supply, and these plants are far more polluting than those in OECD countries. Because of the Olympics, the focus of the world was on China. Though the Central Govt. in China is highly sensitive to the issue of environmental degradation, and incorporates the environmental considerations into policy making, the provincial bodies are keener on meeting the economic goals than protecting the environment.

The Chinese coal, like coal in most parts of the world, contains sulphur (1–5%). When such coal is burnt, SO_2 gets released into the atmosphere. Unless sulphur control technologies or flue-gas desulphurisation (FGD) are in place, the noxious gas can cause breathing troubles, and generate acid rain. Sulphur emissions degrade soil, water and biota. It is possible to bring down emissions in combustion plants to 0.05 g of sulphur per megajoule (MJ) of fuel input, by using low-sulphur coal (<0.5% S), and desulphurisation of flue gases (Aswathanarayana, 1995, p. 144). The Chinese Government sought to reduce the SO_2 emissions by 10% in 2005, relative to emissions in 2000. This goal could not be met as 50% of the coal that was burnt could not be washed, and as FGD

(Flue Gas Desulphurisation) facility could be installed in only 45 GW out of 389 GW of coal-fired plants. China's SO_2 emissions are projected to increase from 26 Mt in 2005 to 31 Mt by 2015. The increasing use of natural gas, replacement of coal by fuel oil, and installation of FGD facilities are expected to lead to leveling of SO_2 emissions at 30 Mt by 2030 (Figure 1.9.4, source: "World Energy Outlook 2007", p. 311).

Oxides of Nitrogen (NO_x) are formed in the process of combustion, and can cause acidification, eutrophication and ozone formation. Combustion also produces Particulate Matter (PM), and inhalation of $PM_{2.5}$ (Particulate matter in the range of 2.5 microns) causes lung diseases. Table 1.9.4 gives the emissions of major pollutants in the Reference Scenario.

1.9.8 Coal and climate change

Fossil fuels (coal, oil and natural gas) account for 88% of the world's commercial primary energy. Burning of the fossil fuels leads to the production of climate-relevant emissions of carbon dioxide (CO_2), methane (CH_4), nitrogen oxides (NO_x),

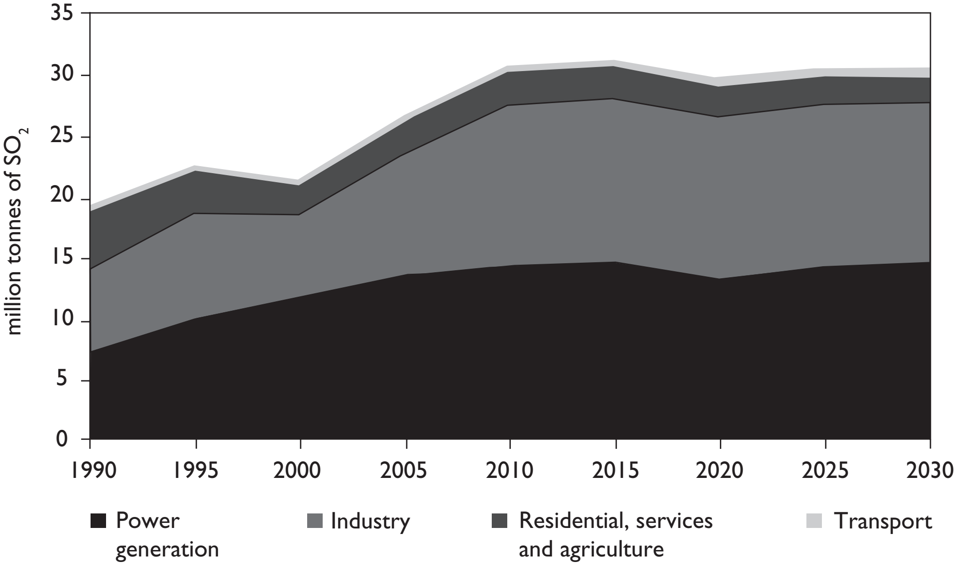

Figure 1.9.4 Sulphur dioxide emissions, sector-wise (See colour plate 3).

Source: World Energy Outlook, 2007, p. 311.

Table 1.9.4 Emissions of major pollutants (in million tonnes).

	1990	*2005*	*2015*	*2030*
NO_x	7	15	19	21
$PM_{2.5}$	12	14	12	9
SO_2	19	26	31	30

carbon monoxide (CO) and volatile organic compounds (VOC). The extent of emissions from various sources is as follows: (i) Energy industries – about 50%, out of which CO_2 accounts for 40%, (ii) Chemical products, particularly, CFCs – about 20%, (iii) Destruction of tropical rain forests and related causes – about 15%, (iv) Agriculture and others (e.g. waste deposit sites) – about 15%.

China is aware that global warming and sea level rise are going to have serious adverse consequences for agriculture, forests and ecosystems, water and the coastal zones in the country. The expected more frequent and intense heat waves are not only debilitating to humans, but are likely to spread malaria and dengue fever.

Though the per capita emissions of CO_2 (3.9 t of CO_2) is only 35% of those in OECD countries, the gross country emissions of CO_2 of China already exceed those of USA, and will continue to be so upto 2030 (Table 1.9.5). Bulk of the CO_2 emissions in China arises from coal. Coal's share of CO_2 emissions is expected to fall marginally from 82% to 78% during 2005–2030.

Table 1.9.6 gives the sectoral distribution of CO_2 emissions.

Table 1.9.5 China's energy-related CO_2 emissions (in tonnes of CO_2).

	2005	*2015*	*2030*
Per capita	3.9	6.2	7.9
Per thousand dollars (year-2006) of GDP	2.2	1.8	1.2
Per toe of primary energy	2.9	3.0	3.0

Source: "World Energy Outlook 2007", p. 313.

Table 1.9.6 Sectoral distribution of energy-related CO_2 emissions (million tonnes).

	1990	*2005*	*2010*	*2015*	*2030*	*2005–2030**
Power generation	652	2,500	3,589	4,450	6,202	3.7%
Industry	800	1,430	2,014	2,186	2,373	2.0%
Transport	121	337	486	664	1,255	5.4%
Residential & Services#	479	468	550	622	715	1.7%
Other@	191	365	585	709	903	3.7%
Total	2,244	5,101	7,233	8,632	11,448	3.3%

* Average annual growth rate; # includes agriculture; @ includes non-energy use.

Source: "World Energy Outlook 2007", p. 314.

Table 1.9.7 Improvement in energy efficiency in some sectors in China.

Indicator	*Unit*	*2000*	*2005*	*2010*
Power generation (coal-fired)	Gram coal equivalent/kW	392	370	355
Raw steel	kgce/t	906	760	730
Synthetic ammonia	kgce/t	1,372	1,210	1,140
Cement	kgce/t	181	159	148
Tiles	kgce/m²	10.04	9.9	9.2

Source: "World Energy Outlook 2007", p. 276.

China is benefiting greatly as the host to generate projects for carbon credits, under Clean Development Mechanism (CDM). China's CDM projects cover renewable energy, energy efficiency, methane recovery, and reduction of emissions of Hydrofluorocarbon, HFC-23. The European Union and Japan are the main buyers of the CDM credits, which could contribute as much as 0.5% of GDP in 2030.

1.9.9 Energy efficiency

Energy efficiency is the ratio between the output of energy (such as, heat and light) to the input of energy. We say that money saved is money earned. In the same manner, energy saved is energy produced. "One dollar invested in more efficient electrical applications saves $3.50 on the supply side" ("World Energy Outlook 2007", p. 361). Saving in energy in some sectors through improved energy efficiency is given in Table 1.9.7.

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SECTION-II
Energy from oil and natural gas

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Kuwait

PREAMBLE

This Section draws extensively from the numerous regular reports from the United States Energy Information Administration (EIA), United States Geological Survey (USGS), and International Energy Agency (IEA).

Oil and natural gas – the products of the burial and transformation of biomass over the last 200 million years – has historically had no equal as an energy source for its intrinsic qualities of extractability, transportability, versatility, and cost. Oil accounts for approximately one-third of all the energy used in the world. EIA projects that oil will continue to be a major source of energy well into the future, with world consumption of petroleum products growing to 118 million barrels per day by 2030. To date, world oil production has come almost exclusively from what are considered to be "conventional sources" of oil, which can be produced using today's mainstream technologies, compared with "nonconventional sources" that require more complex or more expensive technologies to extract, such as oil sands, heavy oil and oil shale.

But the total amount of oil underground is finite, and, therefore, production will one day reach a peak and then begin to decline. Such a peak may be involuntary if supply is unable to keep up with growing demand. Most studies estimate that oil production will peak sometime between now and 2040, although many of these projections cover a wide range of time, including two studies for which the range extends into the next century. Key uncertainties in trying to determine the timing of peak oil are the (1) amount of oil throughout the world; (2) technological, cost, and environmental challenges to produce that oil; (3) political and investment risk factors that may affect oil exploration and production; and (4) future world demand for oil.

The prospect of a peak in oil production presents problems of global proportion whose consequences will depend critically on our preparedness. The consequences would be most dire if a peak occurred soon, without warning, and were followed by a sharp decline in oil production because alternative energy sources, particularly for transportation, are not yet available in large quantities. Such a peak would require sharp reductions in oil consumption, and the competition for increasingly scarce energy would drive up prices, possibly to unprecedented levels, causing severe economic damage. In the longer term, there are many possible alternatives to using oil, but these alternatives will require large investments, and in some cases, major changes in infrastructure or break-through technological advances.

2.1 INTRODUCTION

Fossil fuels continue to supply much of the energy used worldwide, and oil remains the dominant energy source, given its importance in the transportation and industrial end-use sectors. However, global conventional oil supply is currently at *political* risk. This is because the sum of conventional oil production from all countries in the world, except the five main Middle-East suppliers, is near the maximum set by physical resource limits. Should Middle-East suppliers decide to substantially curtail supply, the shortfall cannot be replaced by conventional oil from other sources. The world's production of conventional hydrocarbons will soon decline. Hydrocarbon shortages are inevitable unless radical changes occur in demand, or in the supply of non-conventional hydrocarbons. World conventional oil supply will soon be at physical risk.

The Middle-East countries have only little spare operational capacity, and this will be increasingly called upon as oil production declines elsewhere. Large investments in Middle-East production, if they occur, could raise output, but only to a limited extent (a partial exception is Iraq, but even here, there would be significant delays before prospects are confirmed, and infrastructure is in place). If demand is maintained, and if large investments in Middle-East capacity are not made, the world will face the prospect of oil shortages in the near term. Even with large investments, *resource limits* will force Middle-East production to decline fairly soon, and hence also global conventional oil production. The date of this resource-limited global peak depends on the size of Middle-East reserves, which are poorly known, and unreliably reported. Best estimates put the physical peak of global conventional oil production, in the most optimistic scenarios, before 2040 (Tsoskounoglou et al., 2008).

The world has large quantities of non-conventional oil, and various oil substitutes. But the rapidity of the decline in the production of conventional oil makes it probable that these non-conventional sources cannot come on-stream fast enough to fully compensate. The result will be a sustained global oil shortage. For conventional gas, the world's original endowment is probably about the same, in energy terms, as its endowment of conventional oil. Since less gas has been used so far compared to oil, the world will turn increasingly to gas as oil declines. But the global peak in conventional gas production is already in sight, in perhaps 20 years (Lomborg et al., 2001).

In this Section, aspects of oil and gas that are related to energy issues are reviewed and discussed. These include – reserves and annual production, carbon emissions and climate change, environmental impacts of drilling, refining, pipeline building, industrial effluents and atmospheric pollution, economic, social and political dimensions, and projections in to future. The material for the review is drawn heavily from the numerous regular reports from the United States Energy Information Administration (EIA), United States Geological Survey (USGS), and International Energy Agency (IEA). The Section also includes case studies for the two top-most oil/gas producing countries—Saudi Arabia and Russia.

2.2 WORLD ENERGY STATUS

2.2.1 Consumption and demand

Based on historical data from 1980 to 2005 (during which time the energy demand increased from 284 Quadrillion Btu to 462 Quadrillion Btu, respectively), world energy consumption is projected (EIA, 2008; Fig. 2.2.1) to expand by 50 percent from 2005 to 2030 (695 Quadrillion Btu). The projected energy consumption is further categorized according to the fuel type in Figure 2.2.2, which shows the continued dominance of oil in the future energy portfolio of the world. Given the expectation that world oil prices will remain relatively high throughout the projection, liquid fuels are the world's slowest growing source of energy; liquids consumption increases at an average annual rate of 1.2% from 2005 to 2030. Renewable energy and coal are the fastest growing energy sources, with consumption increasing by 2.1 percent and 2.0 percent, respectively.

Projected high prices for oil and natural gas, as well as rising concern about the environmental impacts of fossil fuel use, improve prospects for renewable energy

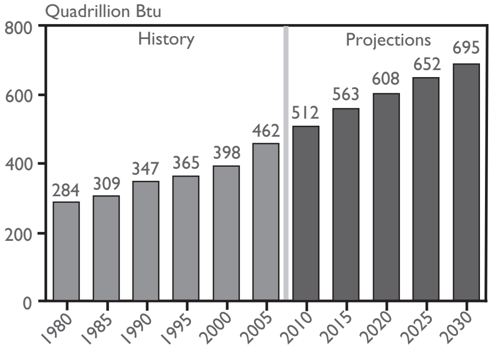

Figure 2.2.1 Historical and projected world energy Consumption (EIA, 2008).

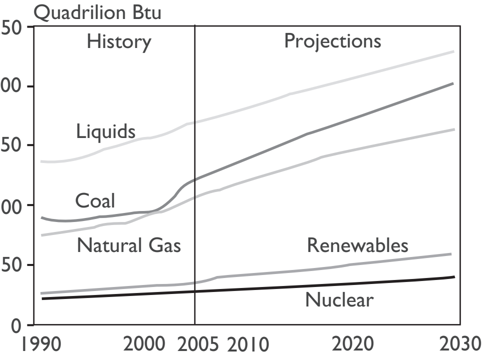

Figure 2.2.2 Historical and projected energy use by fuel type (EIA, 2008).

sources. Coal as an economical choice in future is due to its lower cost relative to the cost of liquids and natural gas, and to abundant resources in large energy-consuming countries. Natural gas remains an important fuel for electricity generation worldwide, because it is more efficient and less carbon intensive than other fossil fuels. The natural gas share increases from 20 percent in 2005 to 25 percent in 2030, and the coal share increases from 41 percent to 46 percent.

As with any set of projections, there is significant uncertainty associated with the EIA (2008) energy projections. The projected energy consumption, referred to as the *reference case* by the EIA, is derived under the assumption of existence of present economic and technical conditions in the world in future. Two sets of sensitivity cases, which vary some of the assumptions behind the projections, are also examined by EIA: the *high and low macroeconomic growth cases* (Fig. 2.2.3) and *high and low energy price cases* (Fig. 2.2.4). These sensitivity cases are intended to illustrate alternative scenarios rather than to identify any bounds on uncertainty,

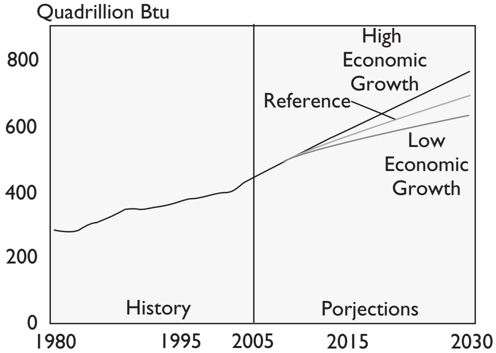

Figure 2.2.3 Projected world energy consumption in the three growth cases (EIA, 2008).

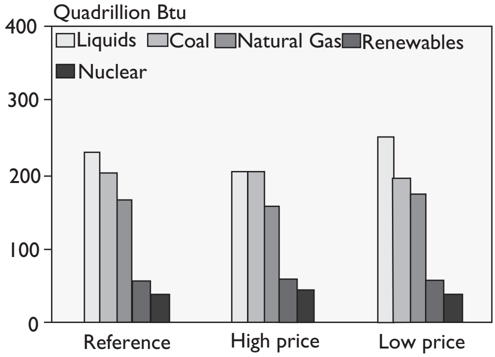

Figure 2.2.4 Projected (2030) world energy consumption in the three price cases (EIA, 2008).

which can be affected by policy and technology developments as well as by price and growth paths.

2.2.2 End-use sector

Outside the transportation sector, which at present is dominated by liquid fuels and other petroleum products (Fig. 2.2.5), the mix of energy use in the residential, commercial, and industrial sectors varies widely by region, depending on a combination of regional factors, such as the availability of energy resources, the level of economic development, and political, social, and demographic factors.

Transportation sector at present is dominated by liquid fuels and other petroleum products. Energy use in the transportation sector includes the energy consumed in moving people and goods by road, rail, air, water, and pipeline. The road transport component includes light-duty vehicles, such as automobiles, sport utility vehicles, minivans, small trucks, and motorbikes, as well as heavy-duty vehicles, such as large trucks used for moving freight and buses for passenger travel. Growth in economic activity and population growth are the key factors that determine transportation sector energy demand. Economic growth spurs increased industrial output, which requires the movement of raw materials to manufacturing sites, as well as movement of manufactured goods to end users.

One primary factor contributing to the expected increase in energy demand for transportation is steadily increasing demand for personal travel in both the non-OECD and OECD economies. Increases in urbanization and in personal incomes have contributed to increases in air travel and to increased motorization (more vehicles) in the growing economies. Modal shifts in the transport of goods are expected to result from continued economic growth in both OECD and non-OECD economies. For freight transportation, trucking is expected to lead the growth in demand for transportation fuels. In addition, as trade among countries increases, the volume of freight transported by air and marine vessels is expected to increase rapidly over the projection period.

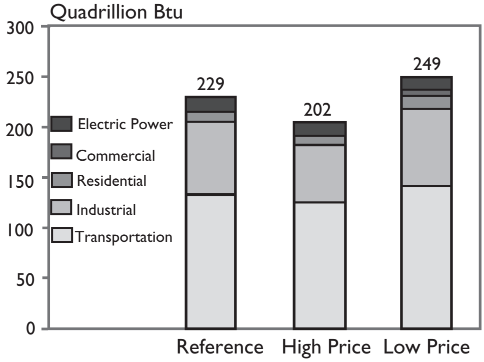

Figure 2.2.5 World consumption of energy from oil, in the five end-use sectors for the three price cases (EIA, 2008).

2.3 ENERGY FROM OIL

2.3.1 Prices and consumption of oil

Up to the beginning of the 21st century, the prices of crude were relatively stable. Oil was sourced mostly from friendly nations and there was always enough reserve production capacity to assure that oil prices – excluding the period of the twin oil crises when prices exploded due to politically induced shortages – would remain low. Real prices stayed between \$10 and \$20/barrel in current dollars and crude oil was a forgotten subject for most analysts. However, the picture changed drastically with the coming of the 21st century. Prices shot up from \$12/barrel in 1999 to close to \$80/barrel in August 2006 and then continued to break all records by approaching \$100/barrel in November 2007 (Tsoskounoglou et al., Fig. 2.3.1), raising fears of whether the world economy is able to climb to new heights. The cause of the current increase in prices is two-sided.

On the one hand is the continuing exponential increase in demand in developing countries like China and India, coupled with the high levels of demand in OECD countries, which necessitate the bringing on stream every year of huge new supplies. On the other hand there exists the increasingly evident difficulty, namely, that oil-producing countries, especially those outside OPEC, have been increasing their production to keep up with demand. The supply difficulties will become worse in the future, whereas the quadrupling of oil prices in the past few years has shown that the price elasticity of oil demand is low, and that the current trend towards more expensive oil will most likely be of a long-term nature. Besides the short-lived disruptions caused by geo-political events, the main factors that have a long-term strong influence on price are demand (Fig. 2.3.2), reserves and new discoveries (Leherrere, 2003; Fig. 2.3.3).

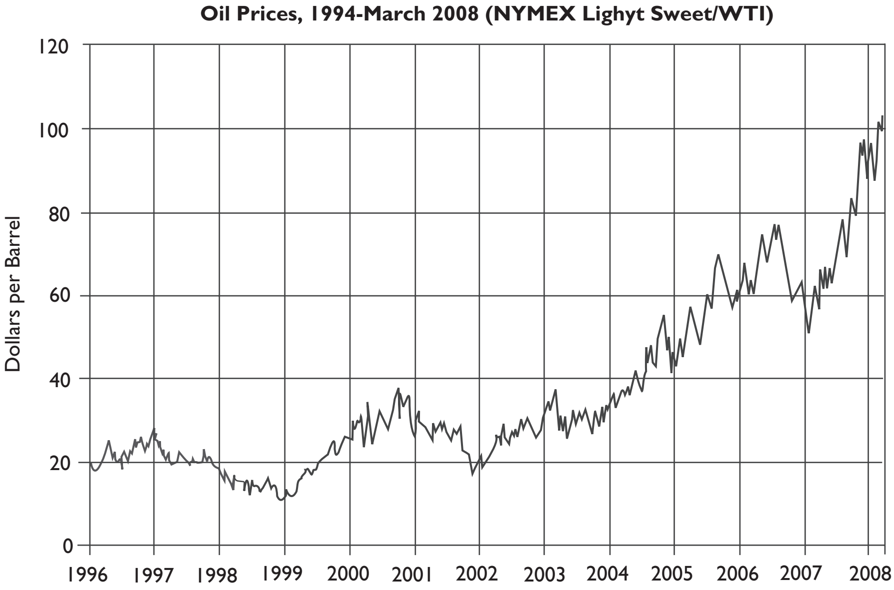

Figure 2.3.1 Oil price changes from 2006 to 2008 (Tsoskounoglou et al., 2008).

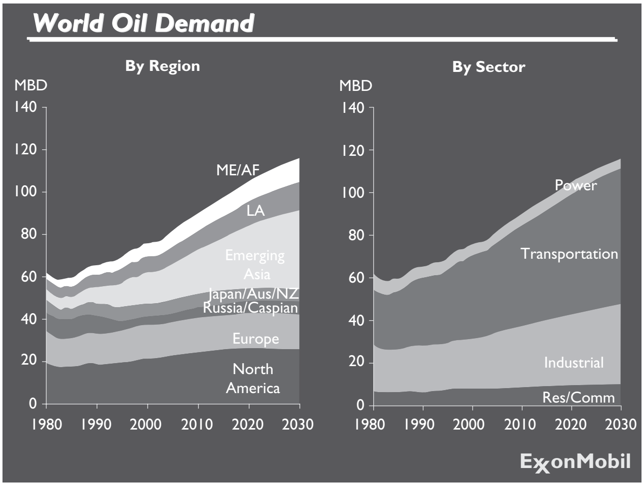

Figure 2.3.2 World oil demand by region and sector (ExxonMobil, 2005).

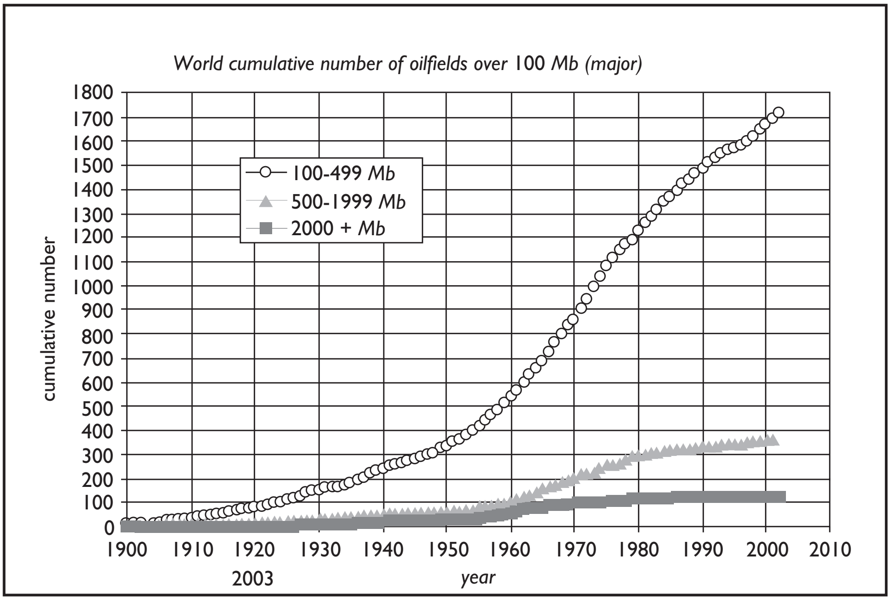

Figure 2.3.3 Past and future oil discoveries (Jean Laherrere, 2003).

Global oil consumption grew by 1.1% in 2007, i.e. 1 million barrels per day (b/d), slightly below the 10-year average. Consumption in the oil-exporting regions of the Middle East, South and Central America and Africa accounted for two-thirds of the world's growth. The Asia-Pacific region grew by 2.3%, roughly in line with the historical average even though growth in China and Japan was below average, with strong growth in a number of emerging economies. OECD consumption fell by 0.9%, or nearly 400,000 b/d. The global growth rate for light distillates matched that of middle distillates for the first time since 2002 due to strong petrochemicals demand.

Global oil production fell by 0.2%, or 130,000 b/d, the first decline since 2002. OPEC production dropped by 350,000 b/d due to the cumulative impact of production cuts implemented in November 2006 and February 2007. Among the 10 members participating in production cuts, crude oil output fell by 900,000 b/d. Saudi Arabia's output dropped by 440,000 b/d, the largest decline in the world last year. Increased output in Angola and Iraq, and growing supply of condensates/natural gas liquids (NGLs), partially offset that decline. Oil production growth outside OPEC remained weak, rising by 230,000 b/d in 2007. OECD output decline was moderate, but nonetheless fell for a fifth consecutive year. Production in both Norway and Mexico declined by more than 200,000 b/d. Former Soviet Union output rose by nearly 500,000 b/d, with production in Azerbaijan and Russia each growing by more than 200,000 b/d. Russian output rose by nearly 500,000 b/d, with Azerbaijan and Russia each growing by more than 200,000 b/d. International trade in crude oil and refined products rose despite OPEC production cuts and rising domestic consumption in oil-exporting countries. Much of this growth was in refined products, a reflection of imbalances and constraints in the world's refining system.

2.3.2 Distribution, reserves and resources of oil

A large volume of studies on the geographic and geological distribution, reserves and resources of oil exists. The most comprehensive has been the petroleum resource assessment conducted by the United States Geological Survey (USGS) on a global scale for 96 countries (USGS, 2000). The USGS World Petroleum Assessment of the quantities of oil, gas, and natural gas liquids (NGL) that have the potential to be added to reserves within a 30-year time frame is the result of a five year effort (1995–2000) of a large team. The assessment is built upon assessment of the geologically defined Total Petroleum Systems (159 TPS) and its subdivisions, Assessment Units (270 AU). Quantitative estimates are given for undiscovered petroleum resources in conventional accumulations and for world-level reserve (field) growth. Assessment units containing continuous-type resources are identified in the world but not quantitatively assessed. Resource estimates were made for parts of 128 geologic provinces in 96 countries (Masters et al., 1998; Fig. 2.3.4).

The USGS considers the geologic characteristics to be the primary criteria for resource assessment. The world has many socio-economic parameters than can affect an assessment based solely on statistics, such as exclusion of areas for development, interruptions by regional or world conflicts, or technology limitations. Geologically defined and analyzed TPS are independent of such socio-economic factors. Additionally, statistics cannot capture ideas and concepts for future exploration. TPS is the fundamental geologic entity that includes the undiscovered resource component and it is more inclusive than petroleum systems as commonly defined. The USGS estimates of world petroleum resources are shown in Figure 2.3.5 and Table 2.3.1.

In the 2008 edition of the *BP Statistical Review of World Energy* (BP, 2008), estimates of proven reserves of oil at the end of 2007 for the six regions (Fig. 2.3.6), historical changes in reserves (Fig. 2.3.7), and reserves for more than fifty individual

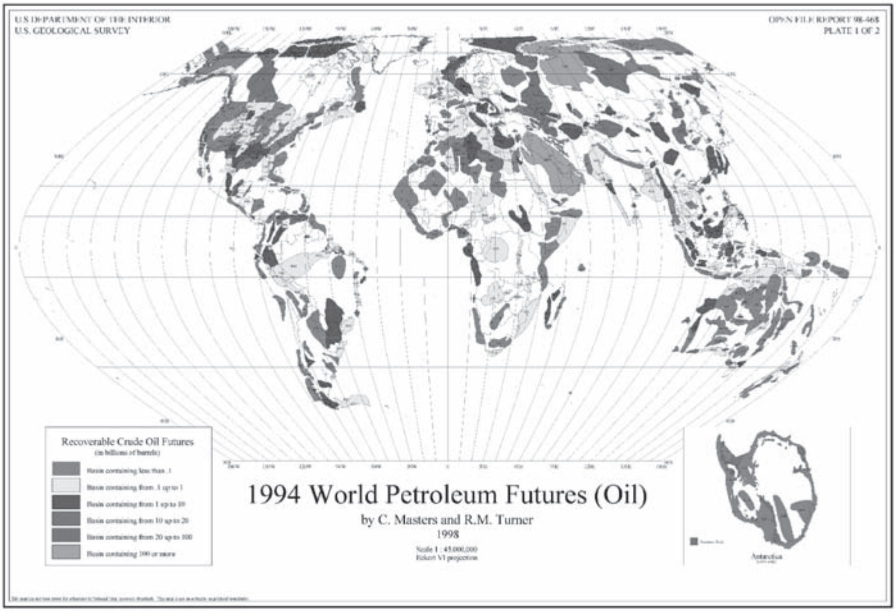

Figure 2.3.4 Geological provinces (128) in different countries (96) in the world and the estimated petroleum resource in each of the province (Masters et al., 1998) (See colour plate 4).

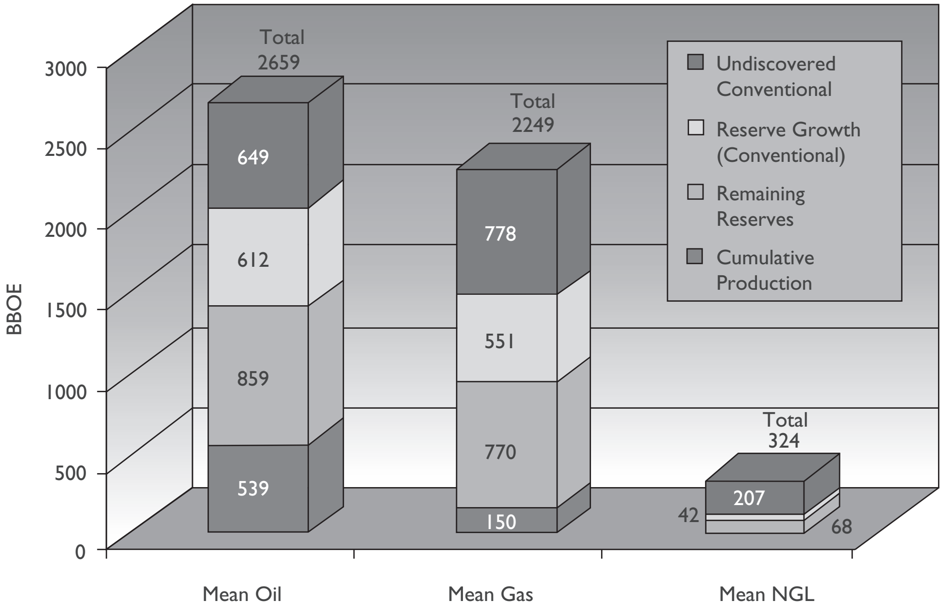

Figure 2.3.5 Estimates of the world oil resources (USGS, 2000).

countries (Table 2.3.2) are given. These estimates of proven reserves by BP are closely compatible with those reported by the U.S. Department of Energy (EIA, 2008: Table 4 & Fig. 34). For comparison, past estimates are given in Figure 2.3.8 (Caruso, 2005). The uneven distribution of the oil reserves has been dramatic, and there is no prognostication of any fundamental change in the future. Since the fundamental geological features (particularly those related to oil generation/accumulation) in the world are well mapped and understood, the USGS probabilistic estimates of future resources from new discoveries is not expected to change the uneven distribution of oil deposits. Even the historical changes (increases) in the reserves in the last 30 years (Fig. 2.3.7) have not changed the geographic uneven distribution pattern. Table 2.3.2 also shows R/P (Reserves/Production) ratios, which is indicative of depletion/exhaustion times (years) for oil reserves. With the present global reserves of approximately 1238 BBO (Billion Barrels of Oil) and production of approximately 82 MBO (Million Barrels of Oil)/day, the exhaustion time is just over 41 years. This "critical" limit and the uneven geographic distribution of oil will continue to have serious geo-political implications in the near (decades at least) future.

2.3.3 Production peak and future demand for oil

There has been much debate on the concept/issue "if and when oil-peak", from production point of view, would take place. A basic tool used in forecasting future oil production and in determining the likely peak in production of any oil-producing region, is the "Hubbert Curve". Hubbert (1956) forecast that the oil production would peak in the beginning of 1970s. His prediction was widely questioned, but when the time came, it was proved correct for oil production in U.S.A. (Fig. 2.3.9). Since then Hubbert's theory, named Peak Oil theory, has gained acceptance. According to Peak Oil theory, the profile of the annual oil production volumes in any oil-producing province tends towards a bell-shaped curve and the maximum of production is reached when about 50% of the ultimate production volume has been extracted. By using Hubbert's curve, one can deduce that global oil production peak will be reached when about 50% of the world's Ultimately Recoverable Resources (URR) have been consumed. The question of how close the world is to the peak, consequently raises the question of how high URR is, and how it compares with the total volume of oil consumed so far.

As new discoveries have been declining for many years (Shell, 2005; Fig. 2.3.10), URR can now be assessed with comparative accuracy and it is estimated by most analysts to be in the region of 2–3 trillion barrels. The only exception is the US Geological Survey (USGS) (2000), whose estimates range from 2.8 to 3.9 trillion barrels, with a mean value of 3.3. Based on the above estimates, and on the fact that we have so far consumed 1 trillion barrels, and currently consuming about 30 billion barrels a year, it can be seen that by applying Hubert's curve, the Peak (when 50% of the URR will have been consumed), is less than 15 years away (Bauquis, 2006; Fig. 2.3.11). If the lower estimates are true, then the Peak has already been reached, or is rapidly approaching. It should be noted that the above forecasts refer only to conventional oil. Non-conventional oil, like the tar sands of Canada or the alternative fuels like biofuels, are subject to a different set of restrictions.

Table 2.3.1 Estimates of oil resources for USA and the rest of the world, at 95%, 50% and 5% probability levels (USGS, 2000).

Rank	*Province code*	*Province name*	*Major commodity*	*Cumulative oil (MMBO)*	*Remaining oil (MMBO)*	*Known oil (MMBO)*	*Mean undiscovered Oil (MMBO)*	*Future oil (MMBO)*	*Oil endowment (MMBO)*	*Discovery maturity, oil (%)*
1	2024	Mesopotamian Foredeep Basin	Oil	56,746	235,696	292,442	61,134	296,830	353,576	83
2	1174	West Siberian Basin	Oil	46,530	93,383	139,913	55,235	148,618	195,148	72
3	2030	Zagros Fold Belt	Oil	49,367	72,234	121,601	45,459	117,693	167,060	73
4	**2019**	**Rub Al Khali Basin**	**Oil**	**19,320**	**70,507**	**89,827**	**36,647**	**107,154**	**126,474**	**71**
5	**2021**	**Greater Ghawar Uplift**	**Oil**	**57,744**	**83,956**	**141,700**	**13,830**	**97,786**	**155,530**	**91**
6	7192	Niger Delta	Oil	16,598	17,925	34,522	40,487	58,412	75,010	46
7	5200	East Greenland Rift Basins	Oil	0	0	0	47,148	47,148	47,148	0
8	**2023**	**Widyan Basin-Interior Platform**	**Oil**	**219**	**17,216**	**17,435**	**21,215**	**38,431**	**38,650**	**45**
9	7203	West-Central Coastal	Oil	5,765	7,952	13,717	29,747	37,699	43,464	32
10	4025	North Sea Graben	Oil	22,467	21,427	43,895	13,098	34,526	56,993	77
11	1016	North Caspian Basin	Oil	822	9,987	10,808	23,320	33,307	34,128	32
12	2043	Sirte Basin	Oil	13,986	23,087	37,072	6,854	29,941	43,927	84
13	6098	East Venezuela Basin	Oil	13,808	16,395	30,203	11,875	28,271	42,078	72
14	5305	Villahermosa Uplift	Oil	14,640	20,382	35,022	7,436	27,818	42,457	82
15	6035	Campos Basin	Oil	1,769	8,287	10,056	16,293	24,580	26,349	38
16	1015	Volga-Ural Region	Oil	42,690	21,247	63,937	2,549	23,796	66,485	96
17	6036	Santos Basin	Oil	6	279	285	23,209	23,488	23,494	1

18	6099	Maracaibo Basin	Oil	35,581	13,491	49,072	8,183	21,675	57,256	86
19	1112	South Caspian Basin	Oil	11,681	5,758	17,438	15,725	21,483	33,163	53
20	**2020**	**Interior Homocline-Central Arch**	**Oil**	**84**	**4,616**	**4,700**	**16,495**	**21,111**	**21,195**	**22**
…										
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	Oil				*Gas*					*NGL*			
	Billion barrels				*Trillion cubic feet*				*BBOE*	*Billion barrels*			
	F95	*F50*	*F5*	*Mean*	*F95*	*F50*	*F5*	*Mean*	*Mean*	*F95*	*F50*	*F5*	*Mean*
World (excluding United States)													
Undiscovered conventional	334	607	1,107	649	2,299	4,333	8,174	4,669	778	95	189	378	207
Reserve growth (conventional)	192	612	1,031	612	1,049	3,305	5,543	3,305	551	13	42	71	42
Remaining reserves*				859				4,621	770				68
Cumulative production*				539				898	150				7
Total				2,659				13,493	2,249				324
United States													
Undiscovered conventional**	66		104	83	393		698	527	88	Combined with oil			
Reserve growth (conventional)**				76				355	59	Combined with oil			
Remaining reserves				32				172	29	Combined with oil			
Cumulative production				171				854	142	Combined with oil			
Total				362				1,908	318				
World Total (including United States)				3,021				15,401	2,567				

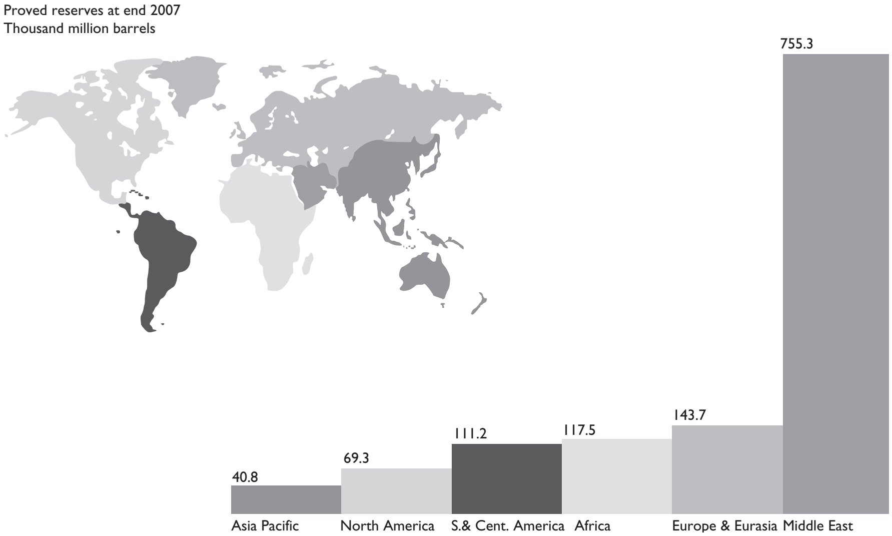

Figure 2.3.6 Proven oil reserves in the six regions of the world (BP, 2008).

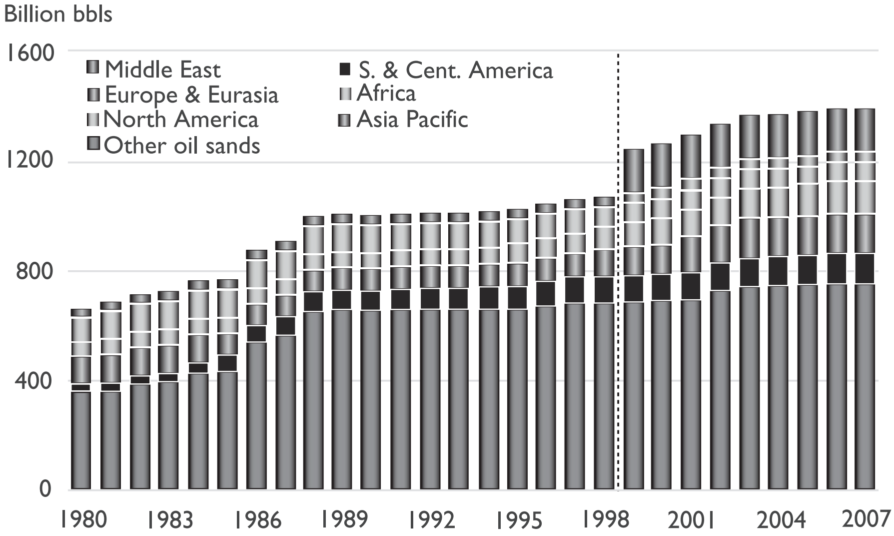

Figure 2.3.7 Changes in global oil reserves from 1980 to 2007 (BP, 2008) (See colour plate 5).

Not all analysts accept Hubbert's theory. For instance, ExxonMobil whose public position on the future of oil production is one of the most optimistic. However, according to a study released by the company (ExxonMobil, 2005), the graph shown in Figure 2.3.12 is depicted, while in the accompanying text the following conclusion is drawn: "Non-OPEC production is expected to peak in the next 10 years or so".

Table 2.3.2 Proven global oil reserves by region and country: R/P is Reserves to annual production ratio (BP, 2008).

	At end 1987	*At end 1997*	*At end 2006*	*At end 2007*			
Proved reserves	*Thousand million barrels*	*Thousand million barrels*	*Thousand million barrels*	*Thousand million barrels*	*Thousand million barrels*	*Share of total*	*R/P ratio*
US	35.4	30.5	29.4	3.6	29.4	2.40%	11.7
Canada	11.7	10.7	27.7	4.2	27.7	2.20%	22.9
Mexico	54.1	47.8	12.8	1.7	12.2	1.00%	9.6
Total North America	**101.2**	**89**	**70**	**9.5**	**69.3**	**5.60%**	**13.9**
Argentina	2.2	2.6	2.6	0.4	2.6	0.20%	10.2
Brazil	2.6	7.1	12.2	1.7	12.6	1.00%	18.9
Colombia	1.9	2.6	1.5	0.2	1.5	0.10%	7.4
Ecuador	1.6	3.7	4.5	0.6	4.3	0.30%	22.5
Peru	0.5	0.8	1.1	0.1	1.1	0.10%	26.4
Trinidad & Tobago	0.6	0.7	0.8	0.1	0.8	0.10%	14.1
Venezuela	58.1	74.9	87	12.5	87	7.00%	91.3
Other S. & Cent. America	0.6	1.1	1.3	0.2	1.3	0.10%	25.2
Total S. & Cent. America	**68.1**	**93.4**	**111**	**15.9**	**111.2**	**9.00%**	**45.9**
Azerbaijan	n/a	n/a	7	1	7	0.60%	22.1
Denmark	0.4	0.9	1.2	0.1	1.1	0.10%	9.8
Italy	0.7	0.8	0.8	0.1	0.8	0.10%	17.6
Kazakhstan	n/a	n/a	39.8	5.3	39.8	3.20%	73.2
Norway	6.6	12	8.5	1	8.2	0.70%	8.8
Romania	1.3	0.9	0.5	0.1	0.5	0.00%	12.4
Russian Federation	n/a	n/a	79.3	10.9	79.4	6.40%	21.8
Turkmenistan	n/a	n/a	0.6	0.1	0.6	0.00%	8.3
United Kingdom	5.2	5.2	3.6	0.5	3.6	0.30%	6
Uzbekistan	n/a	n/a	0.6	0.1	0.6	0.00%	14.3
Other Europe & Eurasia	61.7	68	2.2	0.3	2.1	0.20%	12.8
Total Europe & Eurasia	**75.8**	**88**	**144.1**	**19.4**	**143.7**	**11.60%**	**22.1**
Iran	92.9	82.6	138.4	19	138.4	11.20%	86.2
Iraq	100	112.5	115	15.5	115	9.30%	*
Kuwait	94.5	96.5	101.5	14	101.5	8.20%	*
Oman	4.1	5.4	5.6	0.8	5.6	0.50%	21.3
Qatar	4.5	12.5	27.9	3.6	27.4	2.20%	62.8
Saudi Arabia	169.6	261.5	264.3	36.3	264.2	21.30%	69.5
Syria	1.7	2.3	3	0.3	2.5	0.20%	17.4
United Arab Emirates	98.1	97.8	97.8	13	97.8	7.90%	91.9

(*Continued*)

Table 2.3.2 (Continued)

	At end 1987	*At end 1997*	*At end 2006*	*At end 2007*			
Proved reserves	*Thousand million barrels*	*Thousand million barrels*	*Thousand million barrels*	*Thousand million barrels*	*Thousand million barrels*	*Share of total*	*R/P ratio*
Yemen	1.1	1.8	2.8	0.4	2.8	0.20%	22.7
Other Middle East	0.1	0.2	0.1	+	0.1	0.00%	10.9
Total Middle East	**566.6**	**683.2**	**756.3**	**102.9**	**755.3**	**61.00%**	**82.2**
Ageria	8.6	11.2	12.3	1.5	12.3	1.00%	16.8
Angola	2	3.9	9	1.2	9	0.70%	14.4
Chad	–	–	0.9	0.1	0.9	0.10%	17.2
Republic Of Congo (Brazzaville)	0.7	1.6	1.9	0.3	1.9	0.20%	23.9
Egypt	4.7	3.7	3.7	0.5	4.1	0.30%	15.7
Equatorial Guinea	–	0.6	1.8	0.2	1.8	0.10%	13.2
Gabon	1	2.7	2	0.3	2	0.20%	23.8
Libya	22.8	29.5	41.5	5.4	41.5	3.30%	61.5
Nigeria	16	20.8	36.2	4.9	36.2	2.90%	42.1
Sudan	0.3	0.3	6.6	0.9	6.6	0.50%	39.7
Tunisia	1.7	0.3	0.6	0.1	0.6	0.00%	16.7
Other Africa	1	0.7	0.6	0.1	0.6	0.10%	10.2
Total Africa	**58.7**	**75.3**	**117.1**	**15.6**	**117.5**	**9.50%**	**31.2**
Australia	3.2	4	4.2	0.4	4.2	0.30%	20.3
Brunei	1.6	1.1	1.2	0.2	1.2	0.10%	16.9
China	17.4	17	15.6	2.1	15.5	1.30%	11.3
India	4.4	5.6	5.7	0.7	5.5	0.40%	18.7
Indonesia	9	4.9	4.4	0.6	4.4	0.40%	12.4
Malaysia	3.3	5	5.4	0.7	5.4	0.00%	19.4
Thailand	0.1	0.3	0.5	0.1	0.5	0.30%	4.1
Vietnam	+	1.2	3.3	0.5	3.4	0.10%	27.5
Other Asia Pacific	0.8	1.2	0.9	0.1	0.9	3.30%	11
Total Asia Pacific	**39.8**	**40.4**	**41**	**5.4**	**40.8**	**100.00%**	**14.2**
Total world	**910.2**	**1069.3**	**1239.5**	**168.6**	**1237.9**	**0.50%**	**41.6**
of which: European Union	9	8.8	6.9	0.9	6.8	7.10%	7.8
OECD	119.1	113.4	89.5	11.9	88.3	75.50%	12.6
OPEC	676	818.7	935.3	127.6	934.7	14.10%	72.7
Non-OPEC	174.7	184.1	176.2	23.6	175	10.40%	14.3
Former Soviet Union	59.5	66.5	128	17.4	128.1		27.4
Canadian oil sands*	n/a	n/a	152.2	24.7	152.2		
Proved reserves and oil sands	n/a	n/a	1391.7	193.4	1390.1		

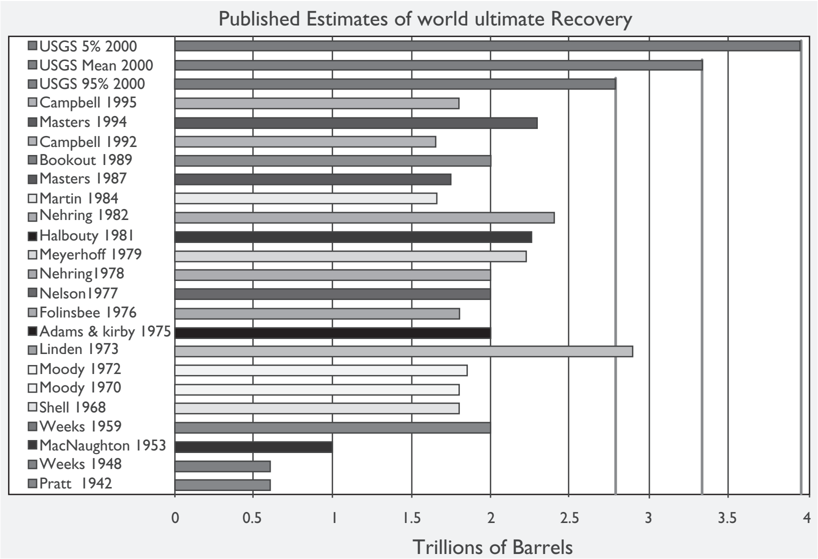

Figure 2.3.8 Past estimates of world ultimate oil resources (Caruso, 2005) (See colour plate 6).

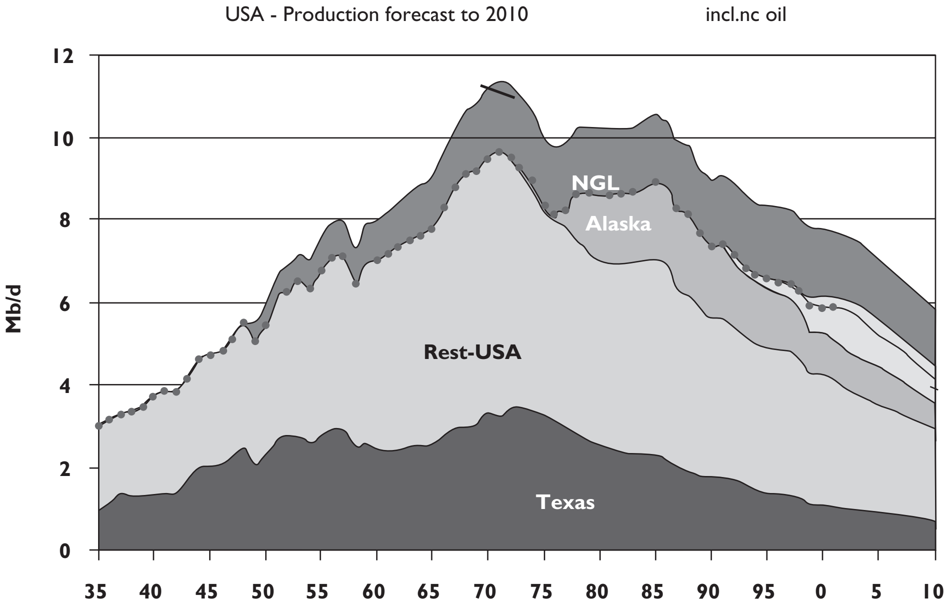

Figure 2.3.9 Forecast of oil production in the USA (Hubbert, 1956).

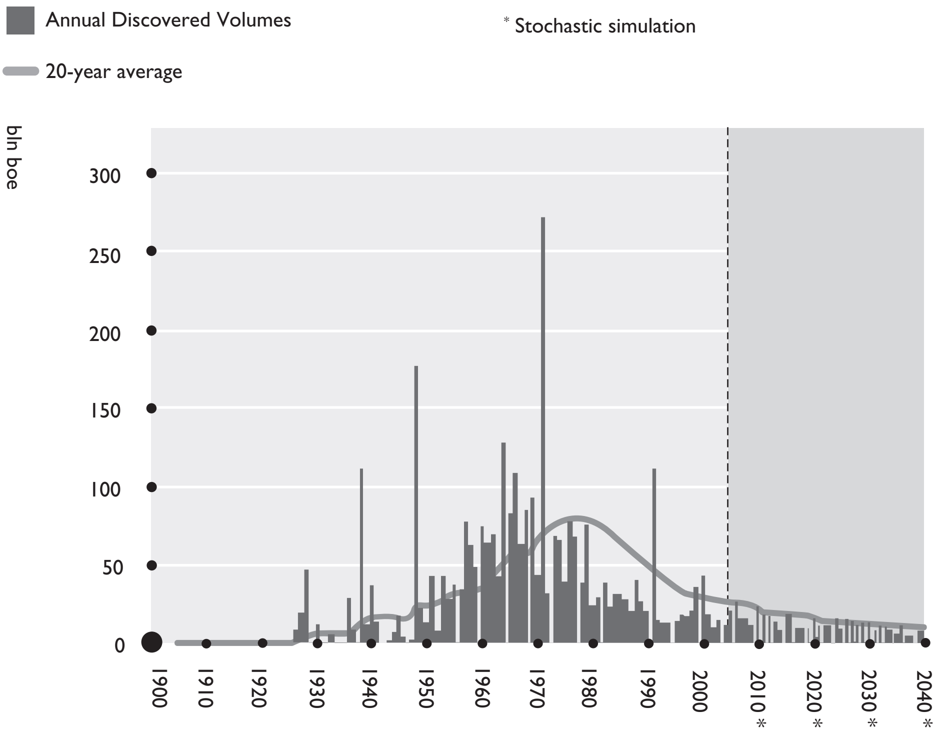

Figure 2.3.10 Past and future projected oil discoveries (Shell, 2005).

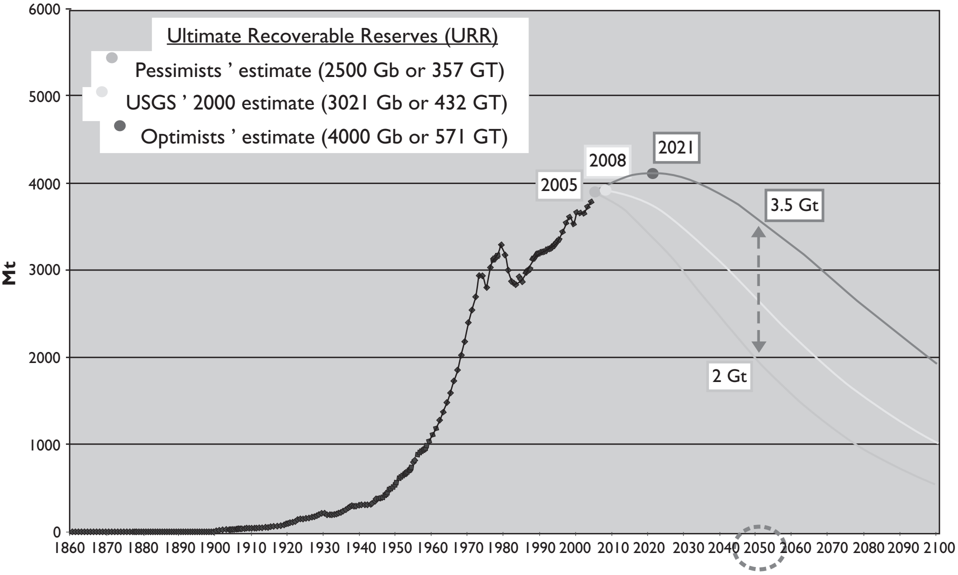

Figure 2.3.11 Global prediction of Peak Oil using Hubert Curve (Bauquis, 2006).

As can be seen, ExxonMobil makes global peaking of oil production contingent solely on OPEC's ability to keep on increasing production in order to satisfy the world's escalating demand. Nonetheless, the study does not comment on the likely date of OPEC's production peak and on whether OPEC's published oil reserves are correct or not.

2.3.3.1 Carbon dioxide emissions from oil usage

According to US Department of Energy estimates, total energy-related carbon dioxide emissions from the non-OECD countries grew by 6.6 percent, while emissions from the OECD countries grew by less than 1 percent. As such, annual emissions from the non-OECD countries currently exceed total annual emissions from the OECD countries, and the difference is growing (EIA, 2008; Fig. 2.3.13). Anthropogenic emissions of carbon dioxide result primarily from the combustion of fossil fuels for

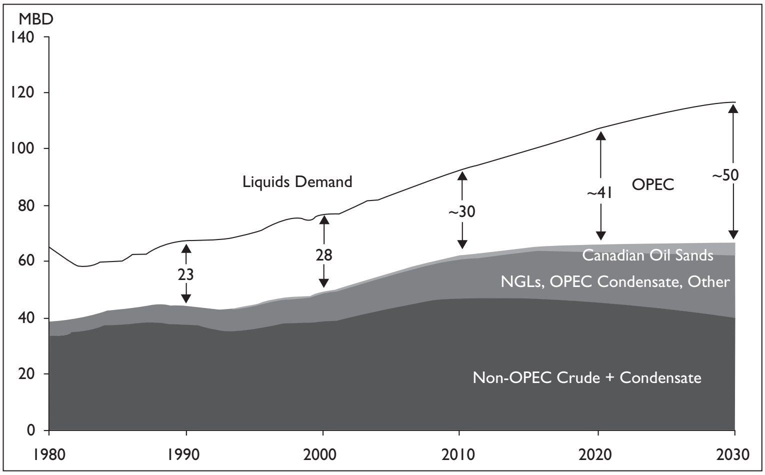

Figure 2.3.12 Historical liquids production and outlook (ExxonMobil, 2005).

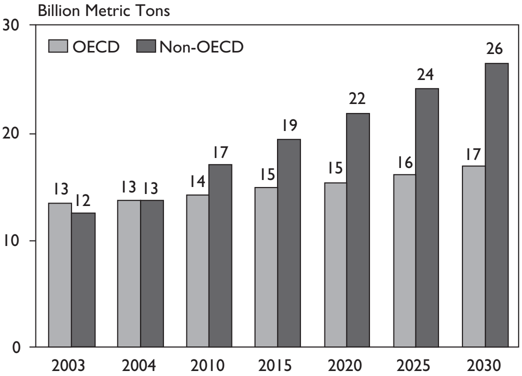

Figure 2.3.13 Present and projected world energy-related carbon dioxide emissions (EIA, 2008).

energy, and world energy use has emerged at the center of the climate change debate. The relative contributions of different fossil fuels to total energy-related carbon dioxide emissions have changed over time. In 1990, emissions from the combustion of liquids and other petroleum made up an estimated 42 percent of the world total; in 2005 their share was 39 percent; and in 2030 it is projected to be 35 percent (Fig. 2.3.14). Carbon dioxide emissions from natural gas combustion, which accounted for 19 percent of the total in 1990, increased to 20 percent of the 2005 total. That share is projected to stabilize at between 20 and 21 percent from 2005 to 2030.

World carbon dioxide emissions from the consumption of liquid fuels and other petroleum are projected to grow at an average annual rate of 1.2 percent from 2005 to 2030. The average growth rates for the OECD and non-OECD countries are projected to be 0.3 percent and 2.2 percent per year, respectively (Fig. 2.3.15; Table 2.3.3). The highest rate of growth in petroleum-related carbon dioxide

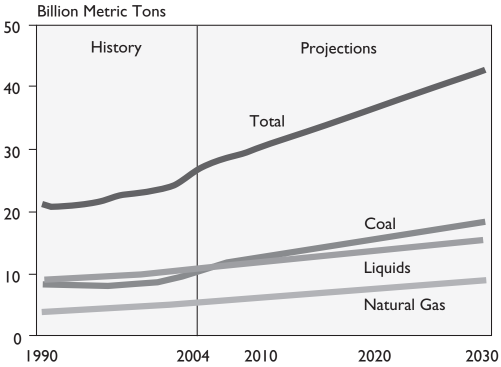

Figure 2.3.14 Present and projected world carbon dioxide emissions by fuel type (EIA, 2008).

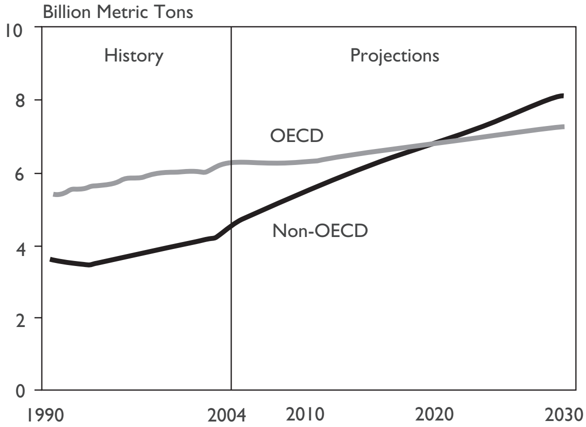

Figure 2.3.15 Present and projected world carbon dioxide emissions by OECD and Non-OECD countries (EIA, 2008).

Table 2.3.3 World carbon dioxide emissions from oil (EIA, 2008).

	History			*Projection*					*Average Annual Percent Change*
Region/Country	*1990*	*2004*	*2005*	*2010*	*2015*	*2020*	*2025*	*2030*	*2005–2030*
OECD									
OECD North America	2,633	3,142	3,169	3,134	3,254	3,302	3,361	3,492	0
United states	2,178	2,597	2,615	2,555	2,636	2,650	2,676	2,767	0
Canada	224	291	290	304	311	319	326	333	0.6
Mexico	231	254	264	275	307	332	359	391	1.6
OECD Europe	1,867	2,097	2,103	2,093	2,151	2,165	2,171	2,174	0
OECD Asia	914	1,016	1,028	1,005	1,049	1,070	1,084	1,097	0
Japan	661	636	643	599	605	602	596	589	0
South Korea	144	238	240	260	285	301	315	328	1
Australia/New Zealand	110	142	144	146	159	166	173	180	1
Total OECD	5,414	6,255	6,300	6,232	6,455	6,537	6,616	6,763	0
Non-OECD									
Non-OECD Europe and Eurasia	1,355	666	673	764	821	875	921	965	2
Russia	783	379	379	416	441	461	473	482	1
Other	572	287	294	348	379	414	448	483	2
Non-OECD Asia	950	1,979	2,037	2,425	2,839	3,248	3,655	4,110	3
China	325	843	880	1,156	1,312	1,544	1,785	2,062	4
India	160	302	303	342	415	481	541	602	3
Other Non-OECD Asia	464	833	854	928	1,112	1,223	1,329	1,440	2
Middle East	488	780	824	960	1,052	1,159	1,250	1,340	2
Africa	298	400	413	482	520	563	586	611	2
Central and South America	503	734	749	866	902	954	1,007	1,067	1
Brazil	180	274	279	320	340	366	391	422	2
Other Central and south America	323	460	470	546	562	588	616	645	1
Total Non-OECD	3,594	4,558	4,697	5,497	6,134	6,800	7,420	8,092	2
Total World	9,009	10,813	10,996	11,729	12,588	13,337	14,036	14,855	1

emissions is projected for China, at 3.5 percent per year, as its demand for liquid fuels increases to meet growing demand in the transportation and industrial sectors. The United States is expected to remain the largest source of petroleum-related carbon dioxide emissions throughout the period, with projected emissions of 2.8 billion metric tons in 2030 – still 34 percent above the corresponding projection for China.

Carbon dioxide emissions from natural gas combustion worldwide are projected to increase on average by 1.7%. Fossil fuel use in the non-OECD countries is projected to increase strongly over the projection period; however, their economic growth is expected to be even stronger. As a result, non-OECD carbon dioxide intensity is projected to decline by an average of 2.6 percent per year, from 529 metric tons per million dollars of GDP in 2005 to 274 metric tons per million dollars of GDP in 2030. In particular, China, with a relatively high projected rate of growth in emissions (3.3 percent per year), has an even higher projected growth rate for GDP (6.4 percent). As a result, its emissions intensity falls from 693 metric tons per million dollars in 2005 to 334 metric tons in 2030.s

2.4 ENERGY FROM NATURAL GAS

2.4.1 Prices and consumption

World natural gas consumption grew by an above-average 3.1% in 2007 (BP, 2008), although only North America, Asia Pacific and Africa recorded above-average regional growth (Fig. 2.4.1, Table 2.4.1). The US accounted for nearly half of the world's gas consumption growth, driven by cold winter weather and strong demand for gas in power generation. Natural gas accounted for nearly all the growth in US energy consumption. Chinese consumption grew by 19.9% and accounted for the second-largest increment to global gas consumption. EU consumption declined by 1.6% – the second consecutive decline – in the face of warm winter weather. Gas production rose by 2.4% in 2007. As was the case for consumption, the US accounted for the largest increment to supply, growing by 4.3%, the strongest growth since1984. EU production declined by 6.4%, with UK output falling by 9.5%, the world's largest volumetric decline for a second consecutive year.

A small decline in Russian production was more than offset by strong growth elsewhere in the Former Soviet Union. China and Qatar recorded the second- and third-largest increments to production, increasing by 18.4% and 17.9% respectively. International trade in natural gas was weak again in 2007, growing by 2.3%, less than half the 10-year average. Global pipeline exports North America, Asia Pacific and Africa recorded stagnation once again, due to weak European above-average regional growth. Liquefied natural gas (LNG) shipments rose by 7.3%, in line with the historical average, supported by continued weather and strong demand for gas in power growth in shipments from Qatar and Nigeria. Atlantic and Pacific basin LNG trade continued all the growth in US energy consumption to integrate. US LNG receipts rose by one-third, Chinese consumption grew by 19.9% and as a large price premium to European spot markets resulted in the diversion of cargoes to the US.

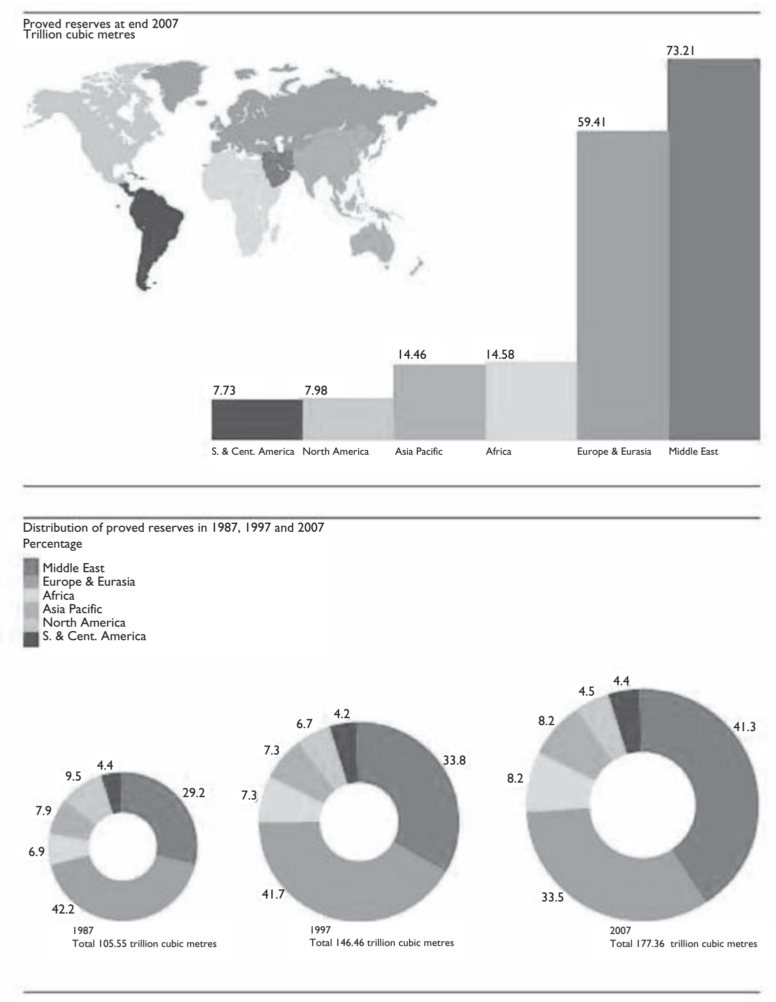

Figure 2.4.1 Gas consumption by region (BP, 2008).

In the U.S. Department of Energy projections (EIA, 2008), worldwide, total natural gas consumption increases from 104 trillion cubic feet in 2005 to 158 trillion cubic feet in 2030 (Fig. 2.4.2). World oil prices are expected to remain high, and as a result natural gas replaces oil wherever possible. In addition, because natural gas produces less carbon dioxide when it is burned than does either coal or petroleum, governments implementing national or regional plans to reduce greenhouse gas emissions may encourage the use of natural gas in the place of other fossil fuels. Natural gas remains a key energy source for industrial sector uses and electricity generation throughout the projection. The industrial sector, which is the world's largest consumer of natural gas, accounts for 43 percent of projected natural gas use in 2030. In the electric power sector, natural gas is an attractive choice for new

Table 2.4.1 World gas consumption from 1965 to 2007 (BP, 2008).

Consumption Billion cubic metres	*1997*	*1998*	*1999*	*2000*	*2001*	*2002*	*2003*	*2004*	*2005*	*2006*	*2007*	*Change 2007Over 2006*	*2007 share of total*
US	643.8	629.9	634.4	660.7	629.7	651.5	630.8	634	623.3	613.1	652.9	6.50%	22.60%
Canada	87.2	83.4	87.4	92.8	88.2	90.2	97.7	95.1	98.1	96.9	94	–3.10%	3.20%
Mexico	32.3	36	36.8	38.3	37.7	41.4	44.5	47.1	46.2	51.4	54.1	5.30%	1.80%
Total North America	**763.3**	**749.4**	**758.6**	**791.8**	**755.6**	**783.1**	**773**	**776.2**	**767.6**	**761.4**	**801**	**5.20%**	**27.60%**
Argentina	28.5	30.5	32.4	33.2	31.1	30.3	34.6	37.9	40.4	41.8	44.1	5.50%	1.50%
Brazil	6	6.3	7.1	9.3	11.7	14.1	15.8	18.7	19.3	20.6	22	7.00%	0.80%
Chile	2.6	3.6	4.9	6.4	7.2	7.3	7.9	8.6	8.3	7.9	4.4	–43.60%	0.20%
Colombia	5.9	6.2	5.1	5.9	6.1	6.1	6	6.3	6.8	7.3	7.7	5.60%	0.30%
Ecuador	0.1	0.1	0.1	0.1	0.2	0.1	+	0.2	0.3	0.3	0.3	–1.90%	0.00%
Peru	0.2	0.4	0.4	0.3	0.4	0.4	0.5	0.9	1.5	1.8	2.7	50.70%	0.10%
Venezuela	30.8	32.3	27.4	27.9	29.6	28.4	25.2	28.4	28.1	27.9	28.5	1.90%	1.00%
Other S. & Cent. America	8.5	10	11.3	11.9	13.6	14.4	15.9	16.2	19.5	23.8	24.9	4.50%	0.80%
Total S. & Cent. America	**82.7**	**89.4**	**88.8**	**95.1**	**99.8**	**101.2**	**106**	**117.3**	**124.3**	**131.3**	**134.5**	**2.50%**	**4.60%**
Austria	8.1	8.3	8.5	8.1	8.6	8.5	9.4	9.5	10	9.4	8.9	–5.30%	0.30%
Azerbaijan	5.6	5.2	5.6	5.4	7.8	7.8	8	8.6	8.9	9.4	8.3	–12.00%	0.30%
Belarus	14.8	15	15.3	16.2	16.1	16.6	16.3	18.5	18.9	19.6	19.4	–1.00%	0.70%
Belgium & Luxembourg	12.5	13.8	15.7	14.9	14.6	14.8	16	16.5	16.6	17	16.9	–0.60%	0.60%
Bulgaria	4.1	3.5	3	3.3	3	2.7	2.8	2.8	2.9	3	3.1	2.00%	0.10%
Czech Republic	8.5	8.5	8.6	8.3	8.9	8.7	8.7	9.1	9.6	9.8	8.9	–9.70%	0.30%
Denmark	4.4	4.8	5	4.9	5.1	5.2	5.2	5.2	5	5.1	4.6	–10.50%	0.20%
Finland	3.2	3.7	3.7	3.7	4.1	4	4.5	4.3	4	4.2	4.1	–4.00%	0.10%
France	34.6	37	37.7	39.7	41.7	41.7	43.3	44.5	45.8	44.1	41.9	–5.00%	1.40%
Germany	79.2	79.7	80.2	79.5	82.9	82.6	85.5	85.9	86.2	87.2	82.7	–5.10%	2.80%

Greece	0.2	0.8	1.5	2	2	2.1	2.4	2.7	2.8	3.2	4	24.30%	0.10%
Hungary	10.8	10.9	11	10.7	11.9	11.8	12.9	12.8	13.2	12.5	11.8	–5.80%	0.40%
Iceland	–	–	–	–	–	–	–	–	–	–	–	–	–
Republic of Ireland	3.1	3.1	3.3	3.8	4	4.1	4.1	4.1	3.9	4.5	4.8	6.80%	0.20%
Italy	53.1	57.2	62.2	64.9	65	64.6	71.2	73.9	79.1	77.4	77.8	0.50%	2.70%
Kazakhstan	7.1	7.3	7.9	9.7	10.1	11.1	13.3	15.4	19.4	20.9	19.8	–5.40%	0.70%
Lithuania	2.6	2.3	2.4	2.7	2.8	2.9	3.1	3.1	3.3	3.2	3.8	17.30%	0.10%
Netherlands	39.1	38.7	37.9	39.2	39.1	39.3	40.3	41.1	39.5	38.3	37.2	–2.90%	1.30%
Norway	3.7	3.8	3.6	4	3.8	4	4.3	4.6	4.5	4.4	4.3	–2.90%	0.10%
Poland	10.5	10.6	10.3	11.1	11.5	11.2	11.2	13.1	13.6	13.7	13.7	–0.10%	0.50%
Portugal	0.1	0.8	2.3	2.4	2.6	3.1	3	3.8	4.2	4.1	4.3	6.60%	0.10%
Romania	20	18.7	17.2	17.1	16.6	17.2	18.3	17.5	17.6	18.2	16.4	–9.90%	0.60%
Russian Federation	350.4	364.7	363.6	377.2	372.7	388.9	392.9	401.9	405.1	432.1	438.8	1.60%	15.00%
Solvakia	6.3	6.4	6.4	6.5	6.9	6.5	6.3	6.1	6.6	6.4	5.9	–7.80%	0.20%
Spain	12.3	13.1	15	16.9	18.2	20.8	23.6	27.4	32.4	33.7	35.1	4.30%	1.20%
Sweden	0.8	0.9	0.8	0.7	0.7	0.8	0.8	0.8	0.8	1	1	3.50%	0.00%
Switzerland	2.5	2.6	2.7	2.7	2.8	2.8	2.9	3	3.1	3	2.9	–2.40%	0.10%
Turkey	9.7	10.3	12.4	14.6	16	17.4	20.9	22.1	26.9	30.5	35.1	15.00%	1.20%
Turkmenistan	10.1	10.3	11.3	12.6	12.9	13.2	14.6	15.5	16.6	18.9	21.9	15.80%	0.70%
Ukraine	74.3	68.7	73	73.1	70.9	69.8	67.8	73.2	73	67.1	64.6	–3.60%	2.20%
United Kingdom	84.5	87.9	93.6	96.9	96.4	95.1	95.4	97.4	94.9	90	91.4	1.50%	3.10%
Uzbekistan	45.4	47	49.3	47.1	51.1	52.4	47.2	44.8	44	43.2	45.6	5.60%	1.60%
Other Europe & Eurasia	14.7	14.6	12.9	13.5	14.7	13.8	14.2	15.4	16.1	16.4	16.8	2.30%	0.60%
Total Europe & Eurasia	**936.3**	**960.3**	**982.9**	**1013.5**	**1025.5**	**1045.6**	**1070.7**	**1104.3**	**1128.3**	**1151.5**	**1155.7**	**0.40%**	**39.40%**
Iran	47.1	51.8	58.4	62.9	70.2	97.2	82.9	93.4	102.4	108.7	111.8	2.90%	3.80%
Kuwait	9.3	9.5	8.6	9.6	8.5	8	9.1	11	12.3	12.9	12.6	–2.30%	0.40%
Qatar	14.5	14.8	14	9.7	11	11.1	12.2	15	18.7	19.6	20.5	4.60%	0.70%

(*Continued*)

Table 2.4.1 (Continued)

Consumption Billion cubic metres	*1997*	*1998*	*1999*	*2000*	*2001*	*2002*	*2003*	*2004*	*2005*	*2006*	*2007*	*Change 2007Over 2006*	*2007 share of total*
Saudi Arabia	45.3	46.8	46.2	49.8	53.7	56.7	60.1	65.7	71.2	73.5	75.9	3.30%	2.60%
United Arab Emirates	29	30.4	31.4	31.4	32.3	36.4	37.9	40.2	41.3	41.7	43.2	3.70%	1.50%
Other Middle East	19.6	20.5	21.5	22.1	22.8	23.6	23.9	27.4	30.9	35	35.3	1.00%	1.20%
Total Middle East	**164.9**	**173.7**	**180.1**	**185.4**	**198.4**	**215.1**	**226.1**	**252.8**	**276.8**	**291.4**	**299.4**	**2.70%**	**10.20%**
Ageria	20.2	20.9	21.3	19.8	20.5	20.2	21.4	22	23.2	23.7	24.4	2.70%	0.80%
Egypt	11.6	12	14.3	18.3	21.5	22.7	24.6	26.2	25.8	29.2	32	9.90%	1.10%
South Africa	–	–	–	–	–	–	–	–	–	–	–	–	–
Other Africa	14.4	14.9	15.5	17.3	17.5	17.9	20.4	22.6	24.3	25	27.1	8.20%	0.90%
Total Africa	**46.1**	**47.7**	**51.2**	**55.5**	**59.5**	**60.8**	**66.4**	**70.8**	**73.3**	**77.9**	**83.5**	**7.20%**	**2.80%**
Australia	19.3	19.8	20.2	20.5	22	22.4	22.4	22.8	21.9	24	25.1	4.90%	0.90%
Bangladesh	7.6	7.8	8.3	10	10.7	11.4	12.3	13.2	14.5	15.3	16.3	6.20%	0.60%
China	19.5	20.3	21.5	24.5	27.4	29.2	33.9	39.7	46.8	56.1	67.3	19.90%	2.30%
China Hong Kong SAR	3.2	3	3.3	3	3	2.9	1.8	2.7	2.7	2.9	3	0.80%	0.10%

India	22.3	24.5	25.1	26.4	26.4	27.6	29.5	31.9	35.7	37.3	40.2	7.60%	1.40%
Indonesia	30.6	29.5	32	30.2	32.3	33.8	34.7	35.7	32.7	34.9	33.8	–3.30%	1.20%
Japan	64.1	66.1	69.4	72.3	74.3	72.7	79.8	77	78.6	83.7	90.2	7.80%	3.10%
Malaysia	16.7	17.4	16.1	24.3	25.8	26.7	27.1	24.5	28.9	29.6	28.3	–4.40%	1.00%
New Zealand	5.1	4.5	5.2	5.5	5.7	5.5	4.1	3.7	3.4	3.5	3.7	6.20%	0.10%
Pakistan	19.8	20.1	22.2	22.8	23.4	22.9	25.2	27.4	30.2	30.5	30.8	1.00%	1.10%
Philippines	+	+	+	+	0.1	1.8	2.7	2.4	3.3	2.9	3.4	19.40%	0.10%
Singapore	1.5	1.5	1.5	1.7	4.5	4.9	5.3	6.6	6.6	6.6	6.6	–	0.20%
South Korea	16.4	15.4	18.7	21	23.1	25.7	26.9	31.5	33.7	35.6	37	4.00%	1.30%
Taiwan	5.2	6.2	6.3	6.8	7.3	8.2	8.4	10.2	10.3	11.1	11.8	6.10%	0.40%
Thailand	16.2	17.6	19.2	22	24.8	26.9	28.8	29.9	32.5	33.3	35.4	6.20%	1.20%
Other Asia Pacific	4.3	4.7	5	5.1	5.2	5.3	5.6	8.9	13.1	13.4	15	11.40%	0.50%
Total Asia Pacific	**251.8**	**258.1**	**274.1**	**296.1**	**316.1**	**327.8**	**348.8**	**367.9**	**395**	**420.9**	**447.8**	**6.40%**	**15.30%**
Total world	**2245.1**	**2278.6**	**2335.7**	**2437.3**	**2455**	**2533.5**	**2590.9**	**2689.2**	**2765.2**	**2834.4**	**2921.9**	**3.10%**	**100.00%**
of which: European Union	400.7	413.5	428	440.4	450	451.1	471.6	485.1	495.5	489.7	481.9	–1.60%	16.40%
OECD	1255.5	1258	1293.6	1346.6	1327.6	1358.5	1378.2	1399	1407.6	1407.7	1454.3	3.30%	49.90%
Former Soviet Union	519.1	529.4	536.2	551.9	552.9	570.3	571.2	589.5	598.6	624.1	631.9	1.20%	21.60%
Other EMEs	470.6	491.2	506	538.9	547.5	604.7	641.5	700.7	758.9	802.5	835.7	4.10%	28.50%

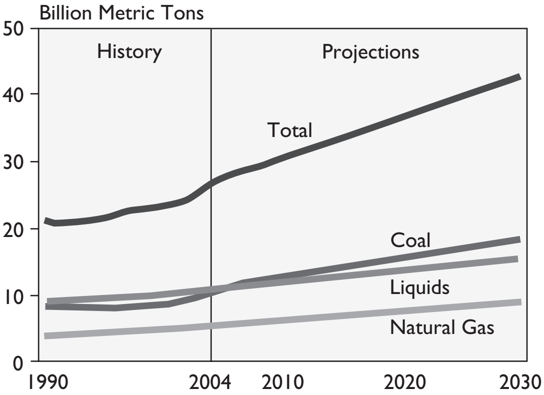

Figure 2.4.2 Past and projected world natural gas consumption (EIA, 2008).

generating plants because of its relative fuel efficiency and low carbon dioxide intensity. Electricity generation accounts for 35 percent of the world's total natural gas consumption in 2030.

Preliminary data for 2006 indicate that natural gas consumption in non-OECD countries has surpassed that in OECD countries. In the *IEO2008* reference case, natural gas consumption in the non-OECD countries grows more than twice as fast as consumption in the OECD countries, with 2.3-percent average annual growth from 2005 to 2030 for non-OECD countries, compared with an average of 1.0 percent for the OECD countries. Natural gas demand in the non-OECD countries accounts for 74 percent of the total world increment in natural gas consumption over the projection period. Natural gas use in the non-OECD countries increases from 50 percent of the world total in 2005 to 58 percent in 2030.

2.4.2 Geographic distribution, reserves and resources

Proven world natural gas reserves were estimated at 6186 trillion cubic feet (OGJ, 2007). The geographic distribution of these reserves is given the U.S. Geological survey (Masters et al., 1998; Fig. 2.4.3) and detailed country-wise estimates are listed in Table 2.4.2 (BP, 2008). Reserves have remained relatively flat since 2004, despite growing demand for natural gas, implying that, thus far, producers have been able to continue replenishing reserves successfully with new resources over time. The largest additions to natural gas reserve estimates in 2008 were reported for Venezuela and Saudi Arabia. Venezuela added an estimated 14 trillion cubic feet (a 9-percent increase over 2007 proved reserves) and Saudi Arabia 13 trillion cubic feet (5 percent). There were smaller, but still substantial, reported increases in reserves in Malaysia and Angola – both of which added around 8 trillion cubic feet. The reserve addition in Malaysia represents an 11-percent increase in its proved reserves. The addition in Angola represents an increase of more than 300 percent. The United States also had a fairly substantial 6-percent increase in reserves, almost 7 trillion cubic feet over the

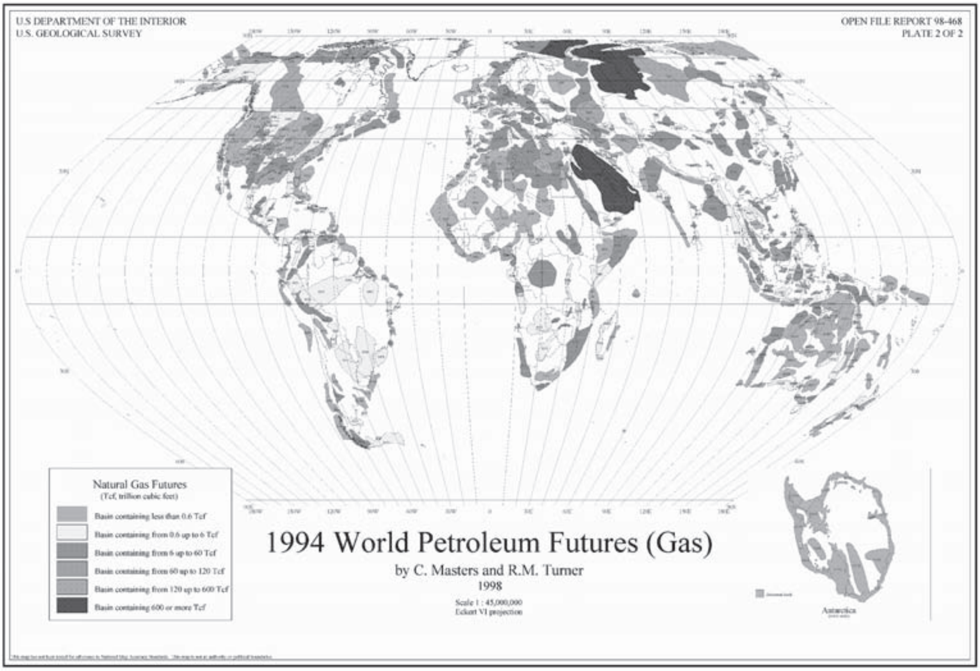

Figure 2.4.3 Geological provinces in the world and the estimated natural gas resource in each of the province (Masters et al., 1998) (See colour plate 7).

2007 estimate. Almost three-quarters of the world's natural gas reserves are located in the Middle East and Eurasia.

Russia, Iran, and Qatar together accounted for about 57 percent of the world's natural gas reserves. Despite high rates of increase in natural gas consumption, particularly over the past decade, most regional reserves-to-production ratios are substantial. Worldwide, the reserves-to-production ratio is estimated at 63 years. By region, the highest ratios are about 48 years for **Central** and South America, 78 years for Russia, 79 years for Africa, and more than 100 years for the Middle East. The largest reported declines in natural gas reserves were reported for Iran (a decrease of 26 trillion cubic feet) and Qatar (5 trillion cubic feet); however, given the vast reserves in each of those countries, the declines represent relatively modest decreases of 3 percent and 1 percent, respectively. A more significant drop in reserves was reported for Papua New Guinea – just over 4 trillion cubic feet, or a 34-percent decrease in the country's total natural gas reserves. Other decreases in proved natural gas reserves were reported for Indonesia (4 trillion cubic feet), Norway, Thailand, Algeria, and Libya (about 3 trillion cubic feet each).

Worldwide undiscovered natural gas is estimated at 4,133 trillion cubic feet (Fig. 2.4.4; USGS, 2000). Of the new natural gas resources expected to be added through 2025, reserve growth accounts for 2,347 trillion cubic feet.

Table 2.4.2 Proven global natural gas reserves by region and country; R/P is Reserves to annual production ratio (BP, 2008).

	At end 1987	*At end 1997*	*At end 2006*	*At end 2007*			
Proved reserves	*Trillion cubic metres*	*Trillion cubic metres*	*Trillion cubic metres*	*Trillion cubic feet*	*Trillion cubic metres*	*share of total*	*R/P ratio*
US	5.3	4.74	5.98	211.08	5.98	3.40%	10.9
Canada	2.69	1.81	1.62	57.55	1.63	0.90%	8.9
Mexico	2.12	1.8	0.39	13.01	0.37	0.20%	8
Total North America	**10.11**	**8.34**	**7.99**	**281.65**	**7.98**	**4.50%**	**10.3**
Argentina	0.69	0.68	0.45	15.54	0.44	0.20%	9.8
Bolivia	0.14	0.12	0.74	26.13	0.74	0.40%	54.7
Brazil	0.11	0.23	0.35	12.89	0.36	0.20%	32.3
Colombia	0.1	0.2	0.12	4.41	0.13	0.10%	16.2
Peru	0.34	0.2	0.33	12.54	0.36	0.20%	*
Trinidad & Tobago	0.3	0.52	0.48	16.95	0.48	0.30%	12.3
Venezuela	2.84	4.12	5.1	181.87	5.15	2.90%	*
Other S. & Cent. America	0.15	0.15	0.07	2.51	0.07	0.00%	21
Total S. & Cent. America	**4.67**	**6.21**	**7.64**	**272.84**	**7.73**	**4.40%**	**51.2**
Azerbaijan	n/a	0.84	1.26	45.13	1.28	0.70%	*
Denmark	0.07	0.11	0.12	4.1	0.12	0.10%	12.6
Germany	0.38	0.26	0.16	4.84	0.14	0.10%	9.6
Italy	0.3	0.27	0.09	3.14	0.09	0.10%	10
Kazakhstan	n/a	1.87	1.9	67.2	1.9	1.10%	69.8
Netherlands	1.77	1.79	1.32	44.07	1.25	0.70%	19.4
Norway	2.29	3.65	2.89	104.57	2.96	1.70%	33
Poland	0.16	0.16	0.11	3.99	0.11	0.10%	26.4
Romania	0.2	0.37	0.63	22.18	0.63	0.40%	54.4
Russian Federation	n/a	45.17	44.6	1576.75	44.65	25.20%	73.5
Turkmenistan	n/a	2.71	2.67	94.22	2.67	1.50%	39.6
Ukraine	n/a	0.98	1.03	36.24	1.03	0.60%	54
United Kingdom	0.64	0.77	0.41	14.55	0.41	0.20%	5.7
Uzbekistan	n/a	1.63	1.74	61.6	1.74	1.00%	29.8
Other Europe & Eurasia	39.25	0.45	0.44	15.31	0.43	0.20%	39.4
Total Europe & Eurasia	**45.06**	**61.02**	**59.37**	**2097.89**	**59.41**	**33.50%**	**55.2**
Bahrain	0.2	0.14	0.09	3	0.09	0.00%	7.4
Iran	13.92	23	27.58	981.75	27.8	15.70%	*
Iraq	1	3.19	3.17	111.95	3.17	1.80%	*
Kuwait	1.21	1.49	1.78	63	1.78	1.00%	*
Oman	0.27	0.54	0.69	24.37	0.69	0.40%	28.6
Qatar	4.44	8.5	25.64	904.06	25.6	14.40%	*
Saudi Arabia	4.19	5.88	7.07	253.03	7.17	4.00%	94.4

(*Continued*)

Table 2.4.2 (Continued)

	At end 1987	*At end 1997*	*At end 2006*	*At end 2007*			
Proved reserves	*Trillion cubic metres*	*Trillion cubic metres*	*Trillion cubic metres*	*Trillion cubic feet*	*Trillion cubic metres*	*share of total*	*R/P ratio*
Syria	0.13	0.24	0.29	10.17	0.29	0.20%	54.7
United Arab Emirates	5.68	6.06	6.11	215.07	6.09	3.40%	*
Yemen	0.11	0.48	0.49	17.23	0.49	0.30%	*
Other Middle East	+	+	0.05	1.73	0.05	0.00%	18.5
Total Middle East	**31.18**	**49.53**	**72.95**	**2585.35**	**73.21**	**41.30%**	*****
Ageria	3.16	4.08	4.5	159.45	4.52	2.50%	54.4
Egypt	0.31	0.93	2.05	72.85	2.06	1.20%	44.3
Libya	0.73	1.31	1.49	52.8	1.5	0.80%	98.4
Nigeria	2.41	3.48	5.22	186.99	5.3	3.00%	*
Other Africa	0.79	0.82	1.2	42.84	1.21	0.70%	*
Total Africa	**7.39**	**10.62**	**14.46**	**514.92**	**14.58**	**8.20%**	**76.6**
Australia	1.07	1.48	2.49	88.64	2.51	1.40%	62.8
Bangladesh	0.35	0.3	0.39	13.77	0.39	0.20%	24
Brunei	0.33	0.39	0.33	12.11	0.34	0.20%	28
China	0.89	1.16	1.68	66.54	1.88	1.10%	27.2
India	0.55	0.69	1.08	37.26	1.06	0.60%	35
Indonesia	2.37	2.15	2.63	105.94	3	1.70%	45
Malaysia	1.49	2.46	2.48	87.4	2.48	1.40%	40.9
Myanmar	0.27	0.28	0.54	21.19	0.6	0.30%	40.8
Pakistan	0.63	0.6	0.85	30.02	0.85	0.50%	27.6
Papua New Guinea	0.09	0.43	0.44	15.36	0.44	0.20%	*
Thailand	0.18	0.21	0.33	11.65	0.33	0.20%	12.7
Vietnam	+	0.17	0.22	7.77	0.22	0.10%	28.5
Other Asia Pacific	0.23	0.41	0.37	13.02	0.37	0.20%	21.9
Total Asia Pacific	**8.45**	**10.73**	**13.82**	**510.69**	**14.46**	**8.20%**	**36.9**
Total world	**106.86**	**146.46**	**176.22**	**6263.34**	**177.36**	**100.00%**	**60.3**
of which: European Union	3.75	3.85	2.94	100.26	2.84	1.60%	14.8
OECD	17.19	17.05	15.79	556.89	15.77	8.90%	14.4
Former Soviet Union	38.9	53.44	53.46	1890.24	53.53	30.20%	67.7

2.4.3 End-use sector and carbon dioxide emissions

Among the three fossil fuels responsible for the production of carbon dioxide emissions, natural gas is at the bottom, coal at the top and oil in the middle (Fig. 2.4.5). Natural gas remains a key energy source for industrial sector uses and electricity generation. The industrial sector, which is the world's largest consumer of natural gas, accounts for 43 percent of projected natural gas use. In the electric power sector, natural gas is an attractive choice for new generating plants because of its relative high fuel efficiency and low carbon dioxide intensity. Electricity generation accounts for 35 percent of the

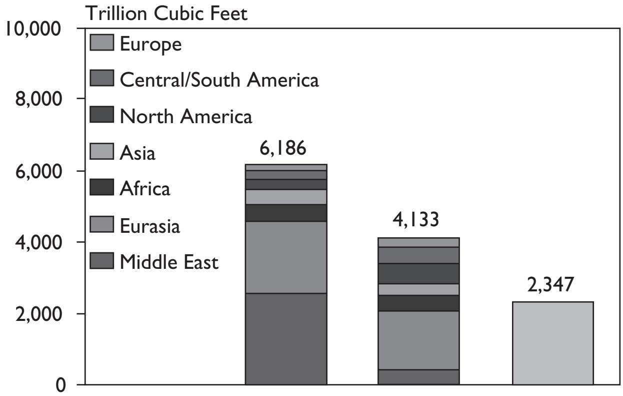

Figure 2.4.4 World natural gas resources by geographic region (EIA, 2008) (See colour plate 8).

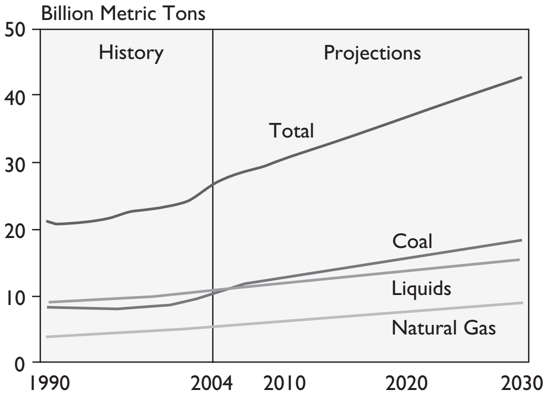

Figure 2.4.5 World energy-related carbon dioxide emissions by fossil fuel-type (EIA, 2008).

world's total natural gas consumption. In Australia and New Zealand, the industrial sector currently is the predominant consumer of natural gas and is projected to account for more than 50 percent of all natural gas consumption in the region. It is also the fastest growing fuel in the region's electric power sector. Australia's ratification of the Kyoto Protocol treaty in March 2008 is likely to increase the country's use of natural gas to displace more carbon-dioxide-intensive coal. In both China and India, natural gas is currently a minor fuel in the overall energy mix, representing only 3 percent and 8 percent, respectively, of total primary energy consumption.

Emissions of carbon dioxide from natural gas combustions are projected to increase on average by 1.7 percent per year, to 8.7 billion metric tons in 2030, with the OECD countries averaging 1.0 percent and the non-OECD countries 2.4 percent (EIA, 2008; Fig. 2.4.6). China is projected to have the most rapid growth in the

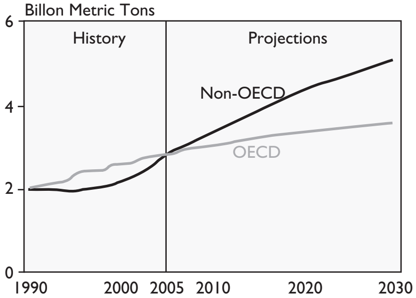

Figure 2.4.6 World carbon dioxide emissions from natural gas combustion (EIA, 2008).

emissions, averaging 5.5 percent annually. The growth in U.S. emissions from natural gas is projected to average 0.1 percent per year.

2.5 TOWARDS EFFICIENT USAGE OF OIL AND NATURAL GAS IN FUTURE

The finite oil and natural gas resources in the world are dwindling fast, particularly oil whose peak production is estimated to occur within two decades at the most, and whose exhaustion is expected around 2050. These two sources of energy are critically important in transportation, industries and in generating electricity, although oil in particular is a very serious contributor for carbon dioxide emissions. However, the possibility of finding alternative sources replacing oil in the transportation industry appears bleak in the short term time perspective. In this scenario of indispensable oil usage, and as a consequence, receiving carbon dioxide emissions into our habitat, policy makers and scientists have been discussing ways to use oil and natural gas more efficiently. The International Energy Agency has been working on this aspect and has produced annual Energy Technology Perspectives (Strategies) reports since 2006. The latest is for the year 2008 (IEA, 2008). This very voluminous and comprehensive document has wealth of information on possible ways towards achieving energy efficiency for the timeframe up to the year 2050. IEA visualizes two scenarios for 2050 – the first one, the ACT scenario is for what needs to be done for bringing back the global Carbon dioxide emissions to the current level in 2050, and the second one, the BLUE scenario is for reducing them to 50% (of the present level) in 2050. IEA emphasizes the urgent need for energy efficiency and new technological breakthroughs in energy utilization and management. Figure 2.5.1 indicates the marginal emission reduction costs (USD/ton of carbon dioxide) for the global energy system under ACT and Blue scenarios. IEA (2008) visualizes that in both the scenarios, the estimated total undiscounted fuel cost savings for oil, natural gas and coal over the period to 2050 are greater than the additional investment required. In addition to their environmental benefits, the ACT and BLUE scenarios also show more balanced outlooks for oil markets. In the ACT scenario,

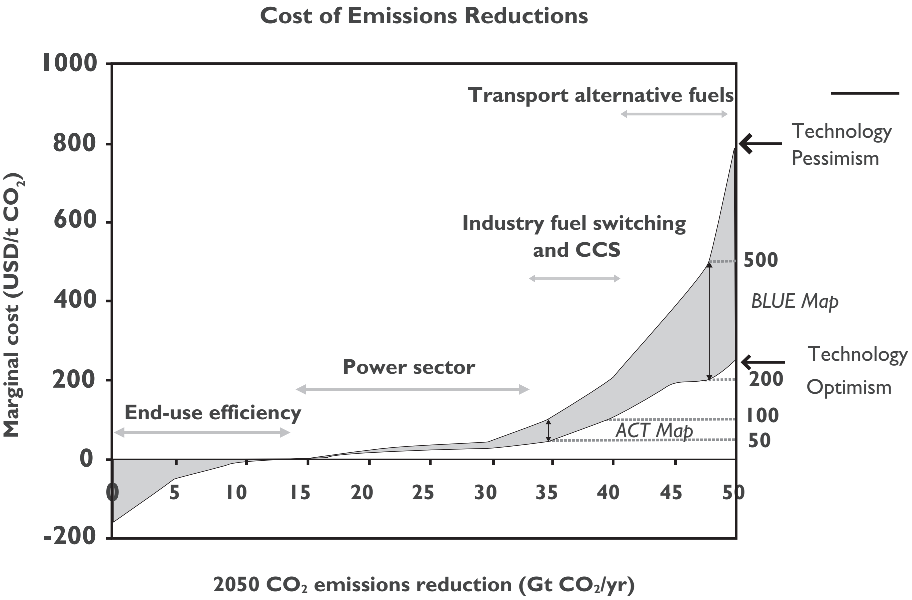

Figure 2.5.1 Marginal emission reduction costs for the ACT and BLUE scenarios for the global energy system (IEA, 2008).

oil continues to grow. It rises by 12% between now and 2050, whereas in the BLUE scenario, it reduces by 27% in 2050. The following is a brief summary with respect to oil and natural gas usage.

2.5.1 Fuel switching

Fuel switching in end-use sectors, particularly in buildings, industry and transportation in which oil plays an important role, could reduce the emissions by 9% to 16% depending on the two scenarios.

2.5.2 End-use efficiency

Energy efficiency improvements constitute the single largest contributor to carbon dioxide emission reduction in both the scenarios. Developments in energy intensity (efficiency) are expected to reduce energy demand by 18% in industry, 40% in transport and 37% in buildings sectors.

2.6 SAUDI ARABIA – COUNTRY CASE STUDY

2.6.1 Introduction

In 1933, the government of Saudi Arabia granted a concession to Standard Oil of California (SOCAL, now Chevron), to explore and produce oil in an area of 495,900 square miles. Several months after signing the agreement, results of preliminary geological research of oil exploration work showed encouraging signs of oil in Jabaladh-Dhahran area. In 1938, oil was discovered in commercial quantities in Dammam Well No. 7 in an area known as the Arab Formation. The first Saudi oil shipment was exported from Ras Tanura Port in May 1939. Discoveries followed with the number of fields discovered reaching 90 in 1999, seven of them are gas fields, one condensates field and the rest are oil fields. Eighty-three of these fields are located within the Saudi Aramco's concession area, and the remaining are in the Neutral Zone's partitioned area. The Saudi Arabian oil is distinct for its diversity. There are five types of crude oil: Arabian heavy, Arabian Medium, Arabian light, Arabian Extra Light and Arabian Super Light. The crude oil and its products are exported via Ras Tanura port (north of Dammam) on the Arabian Gulf and Yanbu' Port on the Red Sea (Fig. 2.6.1).

Gas operations in the Kingdom were completed during the last twenty years because there were no major gas production and distribution operations before the late seventies when the Saudi Government requested Aramco to construct and operate the Master Gas System. By 2000, the proven natural gas reserves in the Kingdom amounted to 219 TCF, i.e. 4% of world reserves. Discoveries of non-associated gas in the Kingdom continued into the nineties at an annual rate of approximately 4 TCF.

Figure 2.6.1 Map of Saudi Arabia with its two main terminals Ras Tanura (near Ad Dammam) on the east coast and at Yanbu al Bahr on the west coast).

Gas production reached 3.5 BCF/d in 1999. All of this gas is consumed domestically, which adds importance to the Kingdom as a major world gas producer and consumer in addition to being an exporter of gas liquids. Natural gas is used for the Kingdom's domestic consumption as a fuel for power generation, seawater desalination and as fuel and feed stock in various industries, mainly the petrochemical industry. Gas operations produce natural gas liquids (NGL), part of which is used domestically for household consumption and as a petrochemical feed stock while the rest is exported to world markets. By 1999 the volume of NGL Production is over 700,000 BPD, of which 143,000 BPD are consumed domestically.

Saudi Arabia has the largest proven oil reserves in the world, estimated to be 267 billion barrels including 2.5 billion barrels in the Saudi-Kuwaiti neutral zone. This is around one-fifth of the world's total conventional oil reserves. Although Saudi Arabia has around 100 major oil and gas fields, over half of its oil reserves are contained in only eight giant oil fields, including the Ghawar Field, the biggest oil field in the world with an estimated 70 billion barrels of remaining reserves. Saudi Arabia maintains the world's largest crude oil production capacity, estimated to be around 11 million barrels per day at mid-year 2008 and has announced plans to increase this capacity to 12.5 million barrels per day by 2009. At the beginning of 2008, the Saudi Arabia was producing around 9.2 million barrels of oil per day. In the summer of 2008, Saudi Arabia announced an increase in planned production of 500,000 barrels per day. However some experts believe Saudi oil production has already peaked or will do so soon.

Despite its large number of oil fields, 90 percent of Saudi Arabia's oil production comes from only five fields, and up to 60 percent of its production comes from the Ghawar field. Since 1982 the Saudis have withheld their well data and any detailed data on their reserves, giving outside experts no way to verify Saudi claims regarding the overall size of their reserves and output. This has caused some to question the current state of their oil fields. In a study discussed in a book by Simmons (2005), 200 technical papers on Saudi reserves by the Society of Petroleum Engineers were analyzed to reach the conclusion that Saudi Arabia's oil production faces near term decline, and that it will not be able to consistently produce more than current levels. Simmons also argues that the Saudis may have irretrievably damaged their large oil fields by over-pumping salt water into the fields in an effort to maintain the fields' pressure and boost short term oil extraction amounts.

2.6.2 Distribution, reserves and resources

The world's 932 giant oil and gas fields are considered those with 500 million barrels of ultimately recoverable oil or gas equivalent. Geoscientists believe these giants account for 40 percent of the world's petroleum reserves. They are clustered in 27 regions of the world, with the two largest clusters in the Arabian Gulf and Western Siberian Basin (Mann et al., 2007; Figures 2.6.2 and 2.6.3). Geophysicists and exploration geologists who look for oil and gas fields classify the subsurface characteristics, or tectonic setting, of geological structures that contain hydrocarbons. Any one oil and gas field may reflect influences from multiple geological periods and events, but geoscientists often attempt to characterize a field based on the dominant geological event that influenced the structure's ability to trap and contain oil and gas in recoverable quantities.

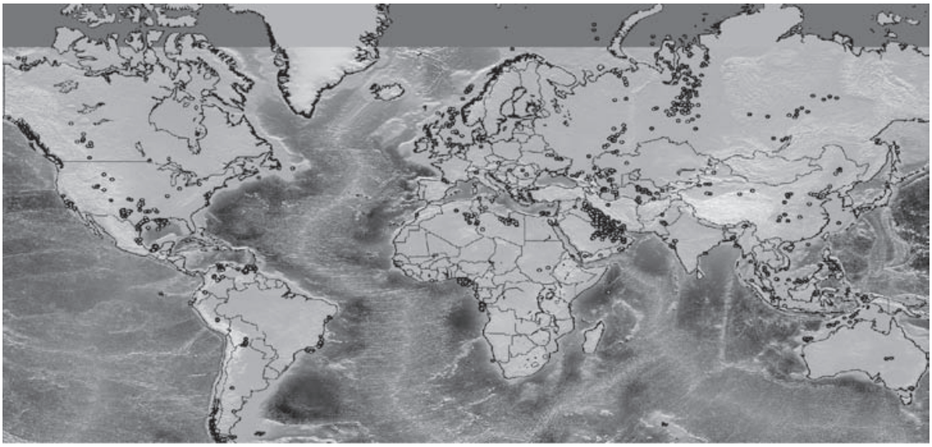

Figure 2.6.2 Distribution of Giant oil fields in the world, indicating two strong clusters in Arabian Gulf and Siberian Basin (Mann et al., 2007) (See colour plate 9).

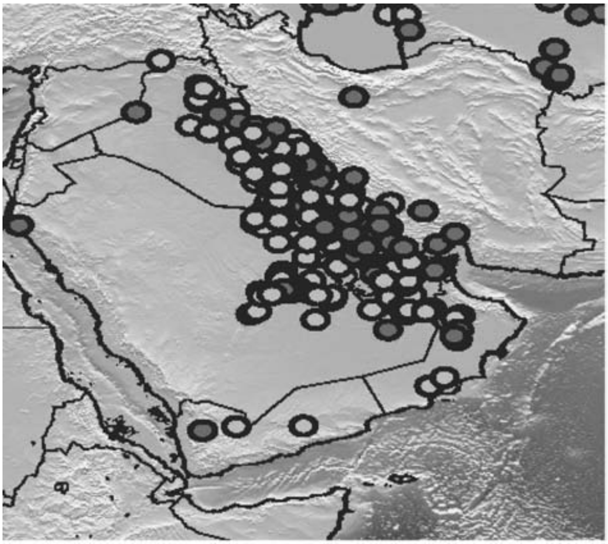

Figure 2.6.3 Clustered distribution of Giant oil fields in the Arabian Gulf region (Mann et al., 2007) (See colour plate 10).

A majority of the world's giant oil and gas fields exist in two characteristic tectonic settings – passive margin and rift environments (Halbouty, 2003). Passive margins are found along the edges of major ocean basins, such as the Atlantic coast of Brazil where oil and gas has been located in large quantities in the Campos basin. Rifts are oceanic ridges formed when tectonic plates separate and a new crust is created. The

North Sea is an example of a rift setting associated with prodigious hydrocarbon reserves. Geoscientists theorize that both zones are especially conducive to forming giant oil and gas fields when they are distant from active tectonic areas. Stability appears to be conducive to generating, trapping and retaining hydrocarbons under the subsurface. Such tectonic stability occurred for long duration (more than 500 million years) in the geological past in the Arabian Gulf region, which has the largest cluster with over 200 of the 932 giant oil fields. The Arabian Gulf was a long lived passive margin of the former Tethyan Ocean that collided with Eurasia in the Cretaceous (90 million years ago).

As part of their global geologically-based (76 geological provinces) assessment of oil and gas resources (*see* Section 2.3.2), the USGS (2000) conducted comprehensive assessment of the resources in the Middle East region. Five of the 76 provinces are in the Persian Gulf region and account for 40% of the world's known petroleum volume, suggesting the geological uniqueness of petroleum occurrence in this region. An estimated two-thirds of the world's ultimately recoverable oil is in the Arabian-Persian Gulf Region and in the Greater Arabian and Greater Oman Basins (Beydoun, 1991; Cole et al., 1994; Alsharhan and Nairn, 1997). Most oil is generated and produced from Jurassic carbonates; however, Cretaceous, Paleozoic, and Infracambrian petroleum systems account for production in numerous giant oil fields in reservoirs of equivalent age. This area of the Middle East is rich in petroleum because it comprised an areally extensive depositional platform along a pre-Mesozoic passive margin of Gondwana. Subsequent development of intra-platform basins, extensive source-rock deposition within these basins, and multiple tectonic stages of compression and extension, produced large subtle structural closures coincident with peak oil generation and migration. Moreover, the large resource base was secured by efficient horizontal hydrocarbon migration into traps underlying thick, regionally extensive evaporite seals.

The five geological provinces (Rub Al Khali Basin, Interior Homocline-Central Arch, Greater Ghawar Uplift, Widyan Basin Interior Platform and Mesopotamian Foredeep Basin) are located in the eastern part of Saudi Arabia (Fox and Ahlbrandt, 2002; Pollastro, 2003; Fig. 2.6.4). The total estimated oil and gas resources from the deposits lying in the five provinces are given in Tables 2.6.1 and 2.6.2, respectively (USGS, 2000). The Tables indicate that, out of the 132 Geological Provinces of the world for which estimates of oil resources are made, 4 of the 5 provinces in the Arabian-Persian Gulf are in the top 10 ranks, reflecting the supreme position Saudi Arabia in the energy spectrum of future. In the case of estimated gas resources also, the region is well endowed. The ranges of three recent estimates of proven reserves (not prognosticated resources) of oil and gas for Saudi Arabia, by different organizations – WO (2006), BP (2007), and OGJ (2007) – are 262–267 BBO (Billion Barrels of Oil) and 2548–2609 TCF (Trillion Cubic Feet of gas).

2.6.3 Production, consumption and exports

Table 2.6.3 lists the summary of energy-related statistics particularly dealing with the production, consumption and export of oil and gas, and Figure 2.6.5 indicates the historical changes in the primary energy production for Saudi Arabia (IEA, 2008). The details are elaborated below.

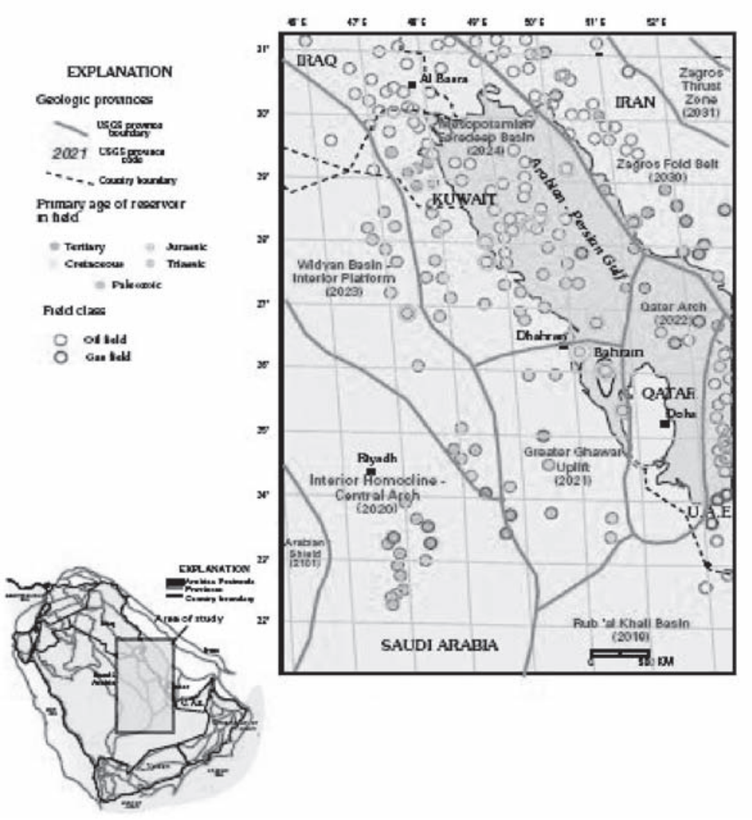

Figure 2.6.4 USGS geologic provinces (2010, 2020, 2021, 2023, 2024) and oil/gas fields of central and northern Arabian-Persian Gulf (Pollastro, 2003) (See colour plate 11).

2.6.3.1 Oil

Production: Saudi Arabia maintains the world's largest crude oil production capacity, estimated to be around 10.5–11 million bbl/d, at mid-year 2008. For 2007, the U.S. Energy Information Administration (EIA) estimates that Saudi Arabia produced on average 10.2 million bbl/d of total oil, comprising crude oil, lease condensate, natural gas liquids, and other liquids (including half of the Saudi-Kuwaiti Neutral Zone's 600,000 bbl/d). In addition to 8.7 million bbl/d of crude oil, Saudi Arabia produced around 1.5 million bbl/d of natural gas liquids (NGLs) and other liquids, which are not subject to OPEC quotas. Saudi Arabia, a leading world producer of NGLs, has experienced a rise in demand for NGLs from developing countries, including India (the leading export destination), where is it used for cooking and transportation. In the first and second quarters of 2008, Saudi Arabia's production rose to an estimated 9.2 million bbl/d of crude oil (13 percent of total world crude production).

In response to historically high oil prices and rising demand, in June 2008, the Ministry of Petroleum and Mineral Resources announced that Saudi Arabia would increase production to around 9.7 million bbl/d in July 2008. The new capacity is expected

Table 2.6.1 Rankings and Estimates of oil resources in the five Petroleum Provinces (province names are in bold) in the Saudi Arabian region (USGS, 2000). MMBO is million barrels of oil. Cumulative oil is the reported volume of oil that has been produced. Remaining oil is the calculated remaining reserves (the difference between known and cumulative oil). Known oil is the reported discovered volume (cumulative production plus remaining reserves). Mean undiscovered oil is the mean volume estimated in World Petroleum Assessment 2000. Future oil is the remaining oil plus estimated mean undiscovered oil. Oil endowment is the known oil plus estimated mean undiscovered oil volumes. Discovery maturity is the percentage of oil discovered (known oil) with respect to oil endowment.

Rank	*Province code*	*Province name*	*Major commodity*	*Cumulative oil (MMBO)*	*Remaining oil (MMBO)*	*Known oil (MMBO)*	*Mean undiscovered oil (MMBO)*	*Future oil (MMBO)*	*Oil endowment (MMBO)*	*Discovery maturity, oil (%)*
1	**2024**	**Mesopotamian Foredeep Basin**	**Oil**	**56,746**	**235,696**	**292,442**	**61,134**	**296,830**	**353,576**	**83**
2	1174	West Siberian Basin	Oil	46,530	93,383	139,913	55,235	148,618	195,148	72
3	2030	Zagros Fold Belt	Oil	49,367	72,234	121,601	45,459	117,693	167,060	73
4	**2019**	**Rub Al Khali Basin**	**Oil**	**19,320**	**70,507**	**89,827**	**36,647**	**107,154**	**126,474**	**71**
5	**2021**	**Greater Ghawar Uplift**	**Oil**	**57,744**	**83,956**	**141,700**	**13,830**	**97,786**	**155,530**	**91**
6	7192	Niger Delta	Oil	16,598	17,925	34,522	40,487	58,412	75,010	46
7	5200	East Greenland Rift Basins	Oil	0	0	0	47,148	47,148	47,148	0
8	**2023**	**Widyan Basin-Interior Platform**	**Oil**	**219**	**17,216**	**17,435**	**21,215**	**38,431**	**38,650**	**45**

9	7203	West-Central Coastal	Oil	5,765	7,952	13,717	29,747	37,699	43,464	32
10	4025	North Sea Graben	Oil	22,467	21,427	43,895	13,098	34,526	56,993	77
11	1016	North Caspian Basin	Oil	822	9,987	10,808	23,320	33,307	34,128	32
12	2043	Sirte Basin	Oil	13,986	23,087	37,072	6,854	29,941	43,927	84
13	6098	East Venezuela Basin	Oil	13,808	16,395	30,203	11,875	28,271	42,078	72
14	5305	Villahermosa Uplift	Oil	14,640	20,382	35,022	7,436	27,818	42,457	82
15	6035	Campos Basin	Oil	1,769	8,287	10,058	16,293	24,580	26,349	38
16	1015	Volga-Ural Region	Oil	42,690	21,247	63,937	2,549	23,796	66,485	96
17	6036	Santos Basin	Oil	6	279	285	23,209	23,488	23,494	1
18	6099	Maracaibo Basin	Oil	35,581	13,491	49,072	8,183	21,675	57,256	86
19	1112	South Caspian Basin	Oil	11,681	5,758	17,438	15,725	21,483	33,163	53
20	**2020**	**Interior Homocline-Central Arch**	**Oil**	**84**	**4,616**	**4,700**	**16,495**	**21,111**	**21,195**	**22**
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Table 2.6.2 Rankings and Estimates of oil resources in the five Petroleum Provinces (province names are in bold) in the Saudi Arabian region (USGS, 2000). BCFG is billion cubic feet of gas. Cumulative gas is the reported volume of gas that has been produced. Remaining gas is the calculated remaining reserves (the difference between known and cumulative gas). Known gas is the reported discovered volume (cumulative production plus remaining reserves). Mean undiscovered gas is the mean volume estimated. Future gas is the remaining gas plus estimated mean undiscovered gas. Gas endowment is the known gas plus estimated mean undiscovered gas volumes. Discovery maturity is the percentage of gas discovered (known gas) with respect to gas endowment.

Rank	*Province code*	*Province name*	*Major commodity*	*Cumulative gas (BCFG)*	*Remaining gas (BCFG)*	*Known gas (BCFG)*	*Mean undiscovered gas (BCFG)*	*Future gas (BCFG)*	*Gas endowment (BCFG)*	*Discovery maturity, gas (%)*
1	1174	West Siberian Basin	Oil	218,465	1,051,584	1,270,049	642,934	1,694,518	1,912,983	66
2	2030	Zagros Fold Belt	Oil	10,333	389,111	399,444	212,008	601,119	611,451	65
3	**2019**	**Rub Al Khali Basin**	**Oil**	**8,303**	**173,934**	**182,237**	**425,712**	**599,646**	**607,949**	**30**
4	2022	Qatar Arch	Gas	1,018	464,582	465,600	17,385	481,967	482,985	96
5	**2021**	**Greater Ghawar Uplift**	**Oil**	**26,493**	**222,057**	**248,550**	**226,969**	**449,026**	**475,519**	**52**
6	**2024**	**Mesopotamian Foredeep Basin**	**Oil**	**13,129**	**285,156**	**298,285**	**83,722**	**368,878**	**382,007**	**78**
7	1154	Amu-Darya Basin	Gas	78,513	151,830	230,343	163,650	315,480	393,993	58
8	1016	North Caspian Basin	Oil	1,745	155,161	156,906	119,051	274,212	275,957	57
9	1050	South Barents Basin	Gas	0	70,020	70,020	160,857	230,877	230,877	30

10	7192	Niger Delta	Oil	6,232	87,579	93,811	132,716	220,295	226,526	41
11	1112	South Caspian Basin	Oil	8,591	27,403	35,994	173,310	200,713	209,304	17
12	6098	East Venezuela Basin	Oil	22,053	106,066	128,119	93,561	199,627	221,679	58
13	4017	Vestford-Helgeland	Oil	0	15,662	15,662	165,201	180,863	180,863	9
14	4025	North Sea Graben	Oil	31,235	128,603	159,839	37,745	166,348	197,584	81
15	**2020**	**Interior Homocline-Central Arch**	**Oil**	**0**	**9,825**	**9,825**	**122,074**	**131,899**	**131,899**	**7**
16	3948	Northwest Shelf	Gas	1,840	54,405	56,245	64,711	119,116	120,956	47
17	2058	Grand Erg/Ahnet Basin	Gas	4,980	109,053	114,034	8,664	117,717	122,697	93
18	**2023**	**Widyan Basin-Interior Platform**	**Oil**	**60**	**7,295**	**7,355**	**94,746**	**102,041**	**102,101**	**7**
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Table 2.6.3 Summary of energy-related statistics, particularly dealing with the production, consumption and export of oil and gas, for Saudi Arabia (IEA, 2008).

	1997	*1998*	*1999*	*2000*	*2001*	*2002*	*2003*	*2004*	*2005*	*2006*	*2007*
Petroleum (Thousand barrels per day)											
Oil production	9400.13	9471.65	8907.02	9475.75	9156.64	8809.51	10076.81	10496.24	11095.56	10664.75	10246.93
Crude oil production	8362.03	8388.9	7833.39	8403.8	8031.10	7634.4	8775	9100.82	9550.14	9152.33	8721.51
Consumption	1383.6	1439.36	1479.22	1537.1	1606.30	1676.25	1774.59	1884.41	2000	2139.42	^{F}2311
Net exports/imports	8016.54	8032.29	7427.79	7938.65	7550.34	7133.26	8302.22	8611.83	9095.56	8525.33	^{F}7936
Oil exports to U.S.	1407	1491	1478	1572	1662	1552	1774	1558	1537	1463	1489
Refinery capacity	1656	1651	1685	1710	1745	1745	1745	1745	1745	2095	2095
Proved reserves (Billion barrels)	261.5	261.5	261.5	263.5	261.7	261.75	261.8	261.9	261.9	266.81	262.3
Natural gas (Billion cubic feet)											
Production	1601.2	1653.4	1631.6	1759.0	1896.1	2002.4	2121.0	2319.5	2515.8	2594.2	NA
Consumption	1601.2	1653.4	1631.6	1759.0	1896.1	2002.4	2121.0	2319.5	2515.8	2594.2	NA
Net exports/imports	0	0	0	0	0	0	0	0	0	NA	NA
Proved reserves	189,100	190,500	204,500	204,500	213,800	219,500	224,700	231,100	235,000	241,840	240,000
Electricity (Billion kilowatt hours)											
Net generation	107.5	114.6	112.8	118.6	125.7	133.2	143.8	150.3	165.6	NA	NA
Net consumption	99.5	108.2	107.1	109.5	118.1	123.4	136.8	139.9	146.9	NA	NA
Capacity (GWe)	21.1	21.7	22.5	22.9	23.8	25.3	28.5	30.2	30.5	NA	NA
Total primary energy (Quadrillion Btu)											
Production	21.2	21.4	20.2	21.6	20.9	20.3	23	24.2	25.5	NA	NA
Consumption	4.4	4.5	4.6	4.9	5.1	5.4	5.8	6.2	6.7	NA	NA
Energy intensity (Btu per 2000 U.S. dollars)	15337.9	15521.9	15842.1	15929.6	16776.4	17553.2	17448.4	17865.6	17979.1	NA	NA
Carbon dioxide emissions (Million metric tons of CO_2)											
Total (from fossil fuels)	254.0	256.8	262.7	289.3	299.9	309.6	344.8	385.8	412.4	NA	NA

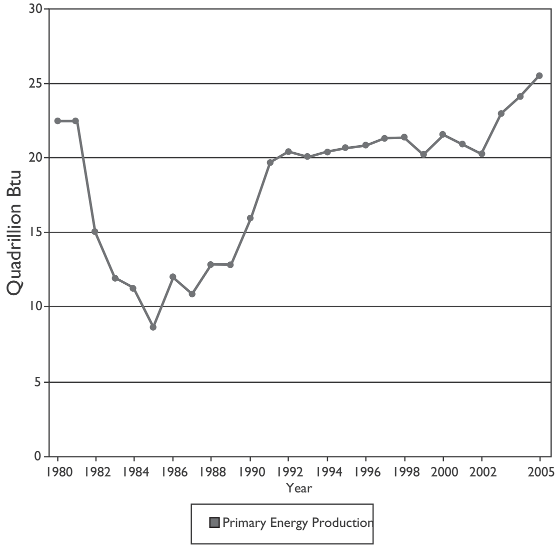


Figure 2.6.5 Historical changes in primary energy production in Saudi Arabia (EIA, 2008).

to come primarily from the Khursaniyah development. Saudi's main producing fields include:

1 Ghawar (onshore): The main producer of more than 5 million bbl/d of 34° API Arabian Light crude (Jaffe and Elsass, 2007; Fig. 2.6.6). Ghawar's main producing structures are, from north to south: Ain Dar, Shedgum, Uthmaniyah, Hawiya, and Haradh. Ghawar alone accounts for about half of Saudi Arabia's total oil production capacity, and is the world's largest oil field.
2 Abqaiq (onshore): Produces approximately 400,000 bbl/d Arab Extra Light crude.
3 Najid (onshore): Since 1994, the Najd fields, which include the Hawtah field and smaller satellites (Nuayyim, Hazmiyah) south of Riyadh, have been producing around 200,000 bbl/d of Arab Super Light.
4 Safaniya (offshore): Producing around 1 million bbl/d of Arab Heavy Crude in 2007 (around 1.2 trillion BBO/d capacity).
5 Zuluf (offshore): Produces approximately 500,000 bbl/d of Arab Medium crude.
6 Marjan (offshore): Produces approximately 270,000 bbl/d of Arab Medium crude.

Saudi Arabia produces a range of crude oils (Table 2.6.4), from heavy to super light. Of Saudi Arabia's total oil production capacity, about 65 to 70 percent is considered light gravity, with the rest either medium or heavy; the country is moving to reduce the share of the latter two grades. Lighter grades generally are produced onshore, while medium and heavy grades come mainly from offshore fields. Most

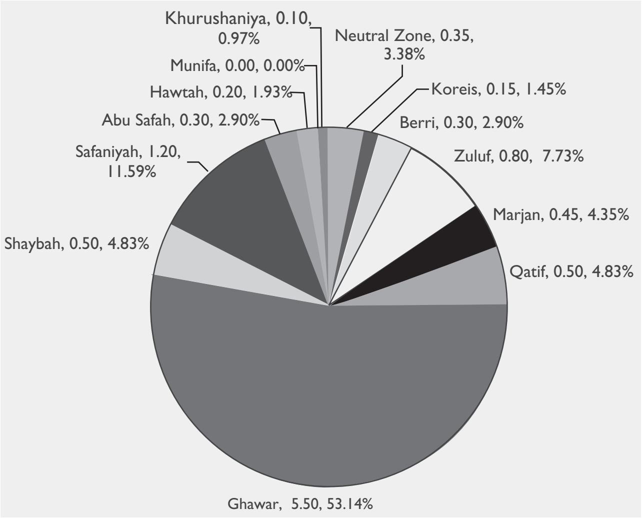


Figure 2.6.6 Amounts and percentages of oil produced by different fields in Saudi Arabia (Jaffe and Elsass, 2007).

Table 2.6.4 Different crude streams produced in Saudi Arabia (EIA, 2008).

Streams	*Estimated production capacity (2007E)*	*Average API*	*Main fields*
Arab super light	250,000	40–50°	Najid fields, Hawtah, Ghinah, Hazmiyah
Arab extra light	1,400,000	36–40°	Berri, Abqaiq, Shaybah
Arab light	7,000,000	32–36 generally in the 33°–34° range	Ghawar (all structures), Khursaniyah and Khurais
Arab medium	1,200,000	29°–32°	Zuluf, Abu Safah, Qatif, Marjan
Arab heavy	1,200,000	<29, Generally around 27.5° and below	Safaniyah, Manifa

Source: Saudi Aramco, Global insight, Energy Intelligence – International Crude Oil Market Handbook 2007, Lehman Brothers Petroleum Markets Update.

Saudi oil production, except for "extra light" and "super light," is considered "sour," containing relatively high levels of sulfur. Saudi Aramco operates the world's largest oil processing facility and crude stabilization plant in the world at Abqaiq, in Eastern Saudi Arabia, with a crude processing capacity of more than 7 million bbl/d. The plant processes the majority of Arabian Extra Light and Arabian Light crude oils, as well as NGLs. The facility's infrastructure includes pumping stations, GOSPs,

Table 2.6.5 Production capacities at different refineries in Saudi Arabia (EIA, 2008).

	2001	*2002*	*2003*	*2004*	*2005*	*2006*
Ras Tanura Refinery	325	325	525	525	535	549
Riyadh Refinery	115	115	122	120	121	125
Jeddah Refinery	60	60	77	84	78	79
Yanbu Refinery	225	225	235	235	215	232
Rabigh Refinery	400	400	370	370	375	374
SAMREF Refinery	365	365	400	400	403	354
SASREF Refinery	305	305	305	313	308	304

hydrodesulphurization units, and an extensive network of pipelines that connects the plant to the ports of Ras al-Juaymah, Ras Tanura and Yanbu (Table 2.6.5). Nearly two-thirds of Saudi crude is processed at Abqaiq before export or delivery to refineries. Saudi Arabia has seven domestic refineries which produce combined crude of around 2.1 MBO/d (of which Aramco's share is approximately 1.7 million bbl/d). Aramco also has interests in another 2 MBO/d of refining capacity overseas, making it the sixth largest oil refiner in the world.

Consumption: In 2007, Saudi Arabia consumed approximately 2.3 million bbl/d of oil, up 50 percent since 2000, due to strong economic and industrial growth and subsidized prices. Saudi Arabia is the largest oil consuming nation in the Middle East. The consumption trends of primary energy, oil and different refined products are given in Figures 2.6.7 and 2.6.8 and Table 2.6.6, respectively.

Exports: Saudi Arabia is the world's largest (net) oil exporter and is a key oil supplier to the United States, Europe and Asia. In 2006, Saudi Arabia exported an estimated 8.5 million bbl/d of petroleum liquids, the majority of which was crude oil. For 2007, EIA estimated that exports fell to 7.9 million bbl/d, of which approximately 85 percent was crude, 10 percent was NGLs and five percent was refined product. Asia, including Japan, South Korea, China, and India, now receives an estimated 50 percent of Saudi Arabia's crude oil exports, as well as the majority of its refined petroleum product and NLG exports (Tables 2.6.7 and 2.6.8; Fig. 2.6.9). Historical changes in the export volumes of oil are shown in Figure 2.6.10. Japan remains the single largest importer of Saudi crude in Asia. According to the International Energy Agency (IEA), in 2007, Japan imported an estimated 1.3 million bbl/d on average. In the same year, South Korea's imports from Saudi decreased by about 70,000 bbl/d to approximately 790,000 bbl/d. China's imports continue to fluctuate widely. In 1995, Saudi Arabia was the 25th largest supplier of crude oil to China; while in 2007, Saudi Arabia was China's largest crude oil supplier (competing with Iran, Angola and Oman). In 2007, China imported approximately 520,000 bbl/d from Saudi Arabia. In 2008, China boosted contracted oil purchases from Saudi Arabia by 38 percent for 2008, rising to approximately 790,000 bbl/d. In 2006 and 2007, Saudi Arabia exported an average of 1.46 million and 1.49 million bbl/d of crude oil respectively to the United States, accounting for 12 percent of U.S. crude

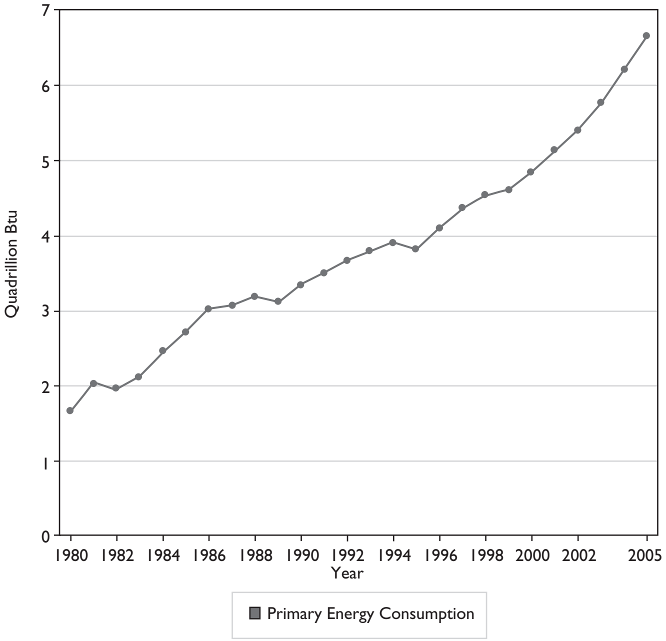


Figure 2.6.7 Historical changes in primary energy consumption in Saudi Arabia (EIA, 2008).

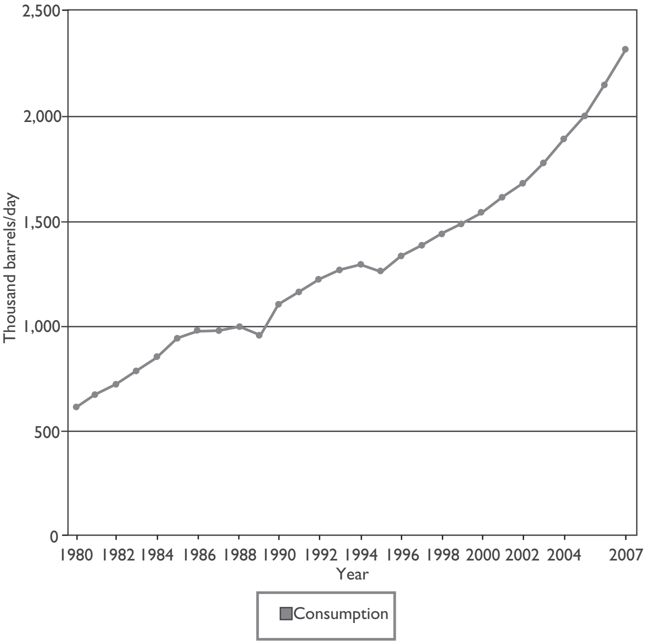


Figure 2.6.8 Historical changes in oil consumption in Saudi Arabia (EIA, 2008).

Table 2.6.6 Consumption of different refined products in Saudi Arabia (EIA, 2008).

	2001		*2002*		*2003*		*2004*		*2005*		*2006*	
Product	*Public*	*Industry*	*Public*	*Industry*	*Public*	*Industry*	*Public*	*Industry*	*Public*	*Industry*	*Public*	*Industry*
LPG	10.52	1.68	10.98	2.11	11.25	2.08	11.61	1.3	12.19	1.04	11,864	1,274
Gasoline	89.82	–	93.51	–	98.96	–	102.69	–	108.79	–	115,300	
Kerosene & jet fuel	19.63	–	19.65	–	21.48	–	20.2	–	20.5	–	20,396	
Diesel	142.85	3.3	142.8	3.94	150.83	2.49	156.44	2.15	164.5	4.11	178,967	4,967
Fuel oil	54.52	10.35	68.01	9.97	84.84	9.66	90.03	9.69	86.28	9.36	93,202	8,302
Fuel gas	–	13.22	–	16.45	–	16.62	–	18.33	–	19.06		19,444
Crude oil	73.95	0.19	60.81	0.01	51.47	0.25	53.02	0.18	58.79	0.23	60,786	201
Asphalt	9.07	–	10.74	–	12.29	–	13.84	–	15.76	–	17,890	
Lube oils	1.48	–	1.83	–	1.81	–	1.7	–	1.99	–	1,599	
Other products	–	1.97	–	4.62	–	5.98	–	6.53	–	4.42		**–782**
Natural gas	238.4	66.68	254.73	72.28	265.82	73.97	310.54	65.6	336.33	80.56	345,883	77,022

Table 2.6.7 Crude oil exports from Saudi Arabia to different countries (EIA, 2008).

	2001	*2002*	*2003*	*2004*	*2005*	*2006*
North America	560.1	488.8	596.9	558.4	558.4	534.5
South America	36.8	22.1	23.8	22.3	22.3	23.8
Western Europe	405.9	343.1	434.9	459.6	459.6	374.8
Middle East	57.4	49.5	72.7	95.5	95.5	109.5
Africa	64.6	68.4	96.3	88.7	88.7	79
Asia & Far East	1068	942.9	1150	1251.1	1251.1	1440.6
Oceania	10.4	14.2	6.3	11.3	11.3	3.5
Total	2203.1	1928.9	2380.9	2486.9	2486.9	2565.7

Table 2.6.8 Refined product exports from Saudi Arabia to different countries (EIA, 2008).

Destination	*2001*	*2002*	*2003*	*2004*	*2005*	*2006*
North America	5.8	4.9	10.6	22.3	18.6	13.2
South America	13.6	10.9	11.4	13.8	12.1	7.2
Western Europe	29.5	18.3	29.8	49.1	55.6	49.6
Middle East	44.9	36.6	45.9	51.8	56.7	72
Africa	37	30	34.3	36.9	41.4	45.2
Asia & Far East	252.3	256.5	276.8	309.6	317.2	275.9
Oceania	12.1	5.5	3.1	3.7	4.1	3.1
Total	395.1	362.6	411.9	487.2	505.7	466.3

oil imports. For this time period, Saudi Arabia ranked third (after Canada, Mexico) as a source of oil imports to the United States.

Saudi Arabia has three primary oil export terminals:

1 The Ras Tanura complex has approximately 6 million bbl/d capacity; and the world's largest offshore oil loading facility. It includes the 2.5-million bbl/d port at Ras Tanura. More than 75 percent of exports are loaded at Ras Tanura Facility.
2 The 3 to 3.6-million bbl/d Ras al-Ju'aymah facility on the Persian Gulf.
3 The Yanbu' terminal on the Red Sea, from which most of the remaining quarter is exported, has loading capacity of approximately 4.5 million bbl/d crude and 2 million bbl/d for NGL and products. The facility is reportedly not used to full capacity. These and a dozen other smaller terminals throughout the country, appear capable of exporting a 14–15 million bbl/d of crude and refined products, around four million bbl/d higher than Saudi Arabia's current crude oil production capacity.

Saudi Aramco operates more than 9000 miles of petroleum pipelines throughout the county, including two major pipelines. The 745-mile, 5 million-bbl/d East-West Crude Oil Pipeline (Petroline), has been operated by Saudi Aramco since 1984 (when it took over from Mobil), and is used mainly to transport Arabian Light and Super Light

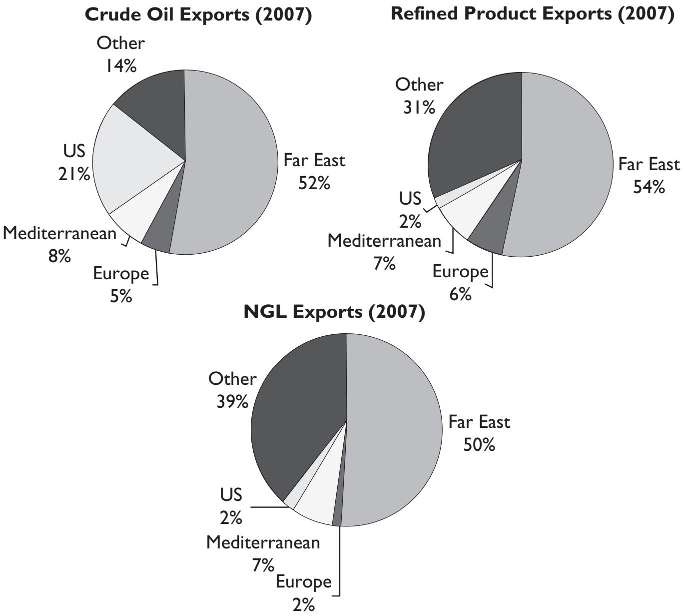


Figure 2.6.9 Crude oil and refined product exports from Saudi Arabia to different countries (EIA, 2008).

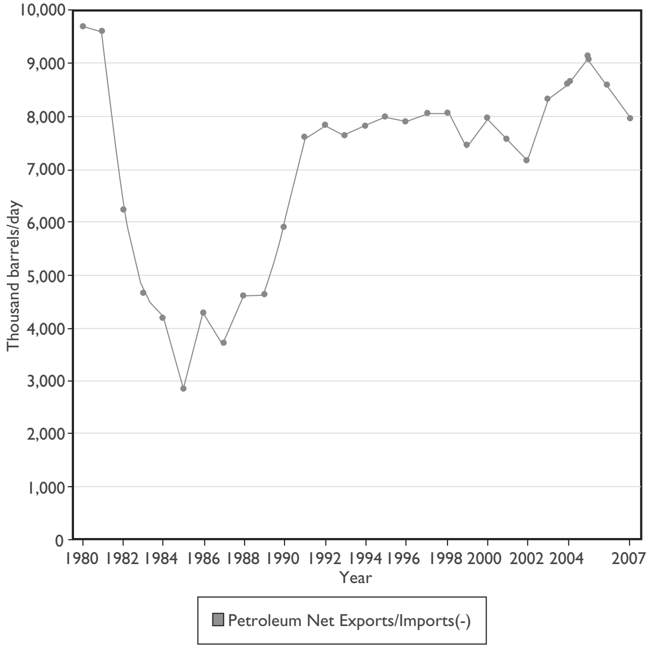


Figure 2.6.10 Historical changes in export of petroleum products from Saudi Arabia (EIA, 2008).

from Abqaiq refineries in the Eastern Province and to Red Sea terminals (Yanbu') for export to European markets. Reportedly, the Saudis expanded the Petroline in part to maintain Yanbu' as a strategic option to Gulf port facilities in the event that exports were blocked from passing through the Straits of Hormuz in the Persian Gulf. Running parallel to the Petroline is the 290,000-bbl/d Abqaiq-Yanbu' natural gas liquids (NGL) pipeline, which serves Yanbu's petrochemical plants. A $500 million contract to install three NGL pipeline loop lines on the Shedgum-Yanbu section of the trunk line, when completed between 2008 and 2009, will increase capacity to 555,000 b/d (SHY-1 expansion). The current capacity is 425,000 b/d.

There are also six smaller pipelines that make up the Uthmaniya – Abqaiq pipeline complex. To support increased export capacity, Aramco has announced the construction of more than 830 miles of new oil, natural gas and NGL pipelines of varying sizes and lengths by 2009. The biggest development will extend to the 1.2 million-b/d Khurais redevelopment, which will require a 400 to 500-mile network in the Eastern Province. The Manifa development has a planned installation of 221 miles of pipeline (gas and crude/condensate).

Saudi Aramco does not operate any major functioning international pipelines. The Trans-Arabian Pipeline (Tapline) from Qaisumah to Sidon, Lebanon, completed in 1974, has been mothballed, in part, since 1984 (the portion to Jordan was closed in 1990, through there has been talk of reopening this portion). Also, a 1.65 million-bbl/d, 48-inch Iraqi Pipeline across Saudi Arabia (IPSA), which runs parallel to the Petroline from pump station #3 (there are 11 pumping stations along the Petroline) to the port of Mu'ajjiz, just south of Yanbu, was built in 1989, but closed indefinitely following the August 1990 Iraqi invasion of Kuwait. In June 2001, Saudi Arabia seized ownership of IPSA. Theoretically, IPSA could be used for Saudi oil transport to the Red Sea, although the Saudis have reported that the pipeline has been converted to carry gas as part of the Master Gas System. The only functioning international crude carrier is a 60-year old complex of four small submarine pipelines carrying Arabian Light crude from the Abu Saafra and Dammam fields to Bahrain. The pipelines range from 207,000 to 250,000 bbl/d capacity. Reportedly, this aging pipeline will be decommissioned after the construction of the "New Arabia" pipeline, a 71-mile, 350,000–450,000-bbl/d capacity feed running between Abqaiq and Bahrain's refinery at Sitra. Despite excess pipeline capacity, the Saudis reportedly are planning to conduct a feasibility study on construction of an oil pipeline from the Empty Quarter of southeastern Saudi Arabia through the Hadramaut in Yemen and the Arabian Sea (as additional strategic alternatives to the Straits of Hormuz), although details of the proposed project were not available.

Saudi Aramco's shipping subsidiary Vela International Marine Ltd. operates the sixth largest fleet of supertankers in the world, including 19 VLCCs (very large crude carriers) and five product tankers. The VLCC is designed to transport between 200,000 – 320,000 dead weight tonnage (dwt) or up to two million barrels of crude oil (per voyage). According to the Saudi Aramco, the total loading capacity is approximately 7.5 million tons. The National Shipping Company of Saudi Arabia (NSCSA) fleet has a total of nine. The company plans to expand the VLCC fleet to 17 vessels, and has signed contracts for taking delivery of eight VLCCs during 2007 and 2009.

2.6.3.2 *Natural gas*

Production: Despite sizable reserves and increasing demand, dry marketed natural gas production and consumption in Saudi Arabia remains limited (2.59 TCF in 2006; Figure 2.6.11; Table 2.6.9). Highly subsidized prices and soaring costs of production, exploration, processing and distribution of gas have squeezed supply, while limiting investment in the sector and constraining other areas of economic and industrial growth. Saudi Arabia has no net imports or exports of natural gas.

Domestic demand, particularly the delivery feedstock to petrochemical plants, has driven consistent expansion of the nearly 8.0 BCF/d Master Gas System (MGS). The MGS feeds gas to the industrial cities including Yanbu' on the Red Sea and

	2001	*2002*	*2003*	*2004*	*2005*	*2006*
Reserves (trilion scf)	227,946	234,673	238,492	241,323	243,648	252,607
Number of discovered fields	12	12	13	14	14	–
Natural gas production (billion cub meters)	57	61.06	67.92	76.46	81.35	85
Natural gas consumption (thousand bbls)	305,080	327,008	339,796	376,140	416,897	528
Gas production (billion cub meter)	–	–	–	2.893	3.019	3

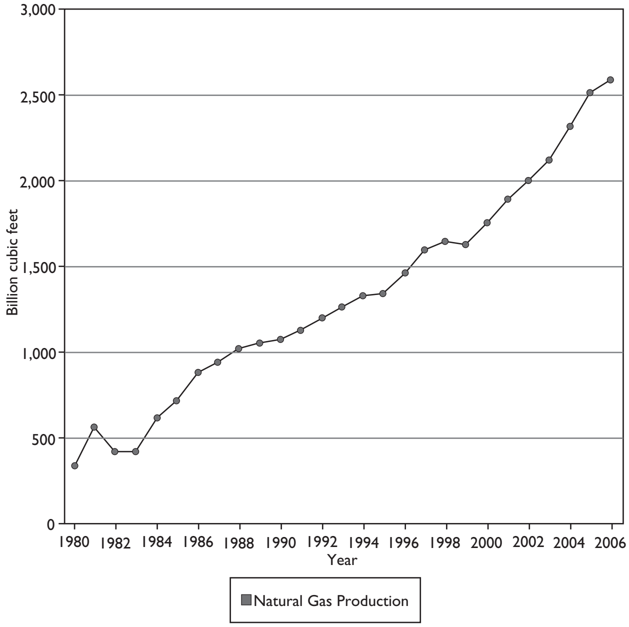


Figure 2.6.11 Historical changes in natural gas production in Saudi Arabia (EIA, 2008).

Table 2.6.9 Production and consumption of natural gas in Saudi Arabia (EIA, 2008).

	1997	*1998*	*1999*	*2000*	*2001*	*2002*	*2003*	*2004*	*2005*	*2006*	*2007*
Petroleum (Thousand barrels per day)											
Oil production	9400.13	9471.65	8907.02	9475.75	9156.64	8809.51	10076.81	10496.24	11095.56	10664.75	10246.93
Crude oil production	8362.03	8388.90	7833.39	8403.80	8031.10	7634.40	8775.00	9100.82	9550.14	9152.33	8721.51
Consumption	1383.60	1439.36	1479.22	1537.10	1606.30	1676.25	1774.59	1884.41	2000.00	2139.42	[F]2311
Net exports/imports	8016.54	8032.29	7427.79	7938.65	7550.34	7133.26	8302.22	8611.83	9095.56	8525.33	[F]7936
Oil exports to U.S.	1407	1491	1478	1572	1662	1552	1774	1558	1537	1463	1489
Refinery capacity	1656	1651	1685	1710	1745	1745	1745	1745	1745	2095	2095
Proved reserves (Billion barrels)	261.500	261.500	261.500	263.500	261.700	261.750	261.800	261.900	261.900	266.810	262.300
Natural gas (Billion cubic feet)											
Production	1601.2	1653.4	1631.6	1759.0	1896.1	2002.4	2121.0	2319.5	2515.8	2594.2	NA
Consumption	1601.2	1653.4	1631.6	1759.0	1896.1	2002.4	2121.0	2319.5	2515.8	2594.2	NA
Net exports/imports	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	NA	NA
Proved reserves	189,100.0	190,500.0	204,500.0	204,500.0	213,800.0	219,500.0	224,700.0	231,100.0	235,000.0	241,840.0	240,000.0
Electricity (Billion kilowatthours)											
Net generation	107.5	114.6	112.8	118.6	125.7	133.2	143.8	150.3	165.6	NA	NA
Net consumption	99.5	108.2	107.1	109.5	118.1	123.4	136.8	139.9	146.9	NA	NA
Capacity (GWe)	21.1	21.7	22.5	22.9	23.8	25.3	28.5	30.2	30.5	NA	NA
Total primary energy (Quadrillion Btu)											
Production	21.2	21.4	20.2	21.6	20.9	20.3	23.0	24.2	25.5	NA	NA
Consumption	4.4	4.5	4.6	4.9	5.1	5.4	5.8	6.2	6.7	NA	NA
Energy intensity (Btu per 2000 U.S. dollars)	15337.9	15521.9	15842.1	15929.6	16776.4	17553.2	17448.4	17865.6	17979.1	NA	NA
Carbon dioxide emissions (Million metric tons of CO_2)											
Total (from fossil fuels)	254.0	256.8	262.7	289.3	299.9	309.6	344.8	385.8	412.4	NA	NA

Jubail. A key pipeline project was completed in June 2000 to extend the MGS from the Eastern Province (which contains large potential gas and condensate reserves) to the capital in the Central Province. This is part of a broader expansion of the existing gas transmission system in Saudi Arabia, reportedly to include the construction of around 1,200 miles of additional natural gas pipeline capacity (on top of 10,500 miles of oil, gas, and condensate, products, and natural gas liquid pipelines currently in operation). The largest pipeline to be built is the 132-mile conduit to the Rabigh complex and the existing Yanbu' NGL processing facility. Installation of four pipelines, totaling some 62-miles will connect Manifa to KGP and Ras az-Zour for gas processing.

2.6.4 End-use sectors and carbon dioxide emissions

2.6.4.1 End-use sectors

The main end-use sectors of energy in Saudi Arabia are industry, transportation, and housing. The combination of Saudi Arabia's rapidly expanding population and industrial base (representing 60 percent of demand), paired with artificially low power tariffs, has increased the demand on electric utilities (averaging 5 to 7 percent annual growth; Figures 2.6.12 and 2.6.13). At times, the increased load has lead to shortages, blackouts and power rations in various parts of the country. According to the 2007 SEC annual report, Saudi Arabia added more than 2.3 GW last year, including expansions at the Shuaibah Power Plant and nearly 900 MW of gas fired turbines in Riyadh (9), Tehama and Jizan. Some of the newest and largest facilities include the $1.7-billion, 2400-MW Ghazlan II plant north of Dammam, the first power project to be debt-financed; its sister plant, the1600-MW Ghazlan I; and the 2500-MW Qurayya I and II. Separately, Saudi Aramco is building a series of co-generation plants at oil and gas installations throughout the country in order to reduce drain of the energy sector on

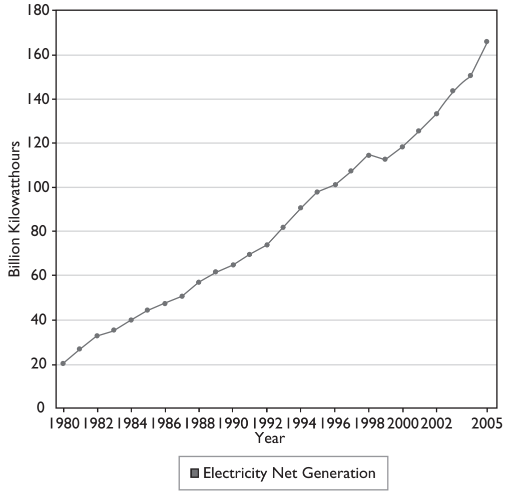


Figure 2.6.12 Historical changes in electricity generation in Saudi Arabia (EIA, 2008).

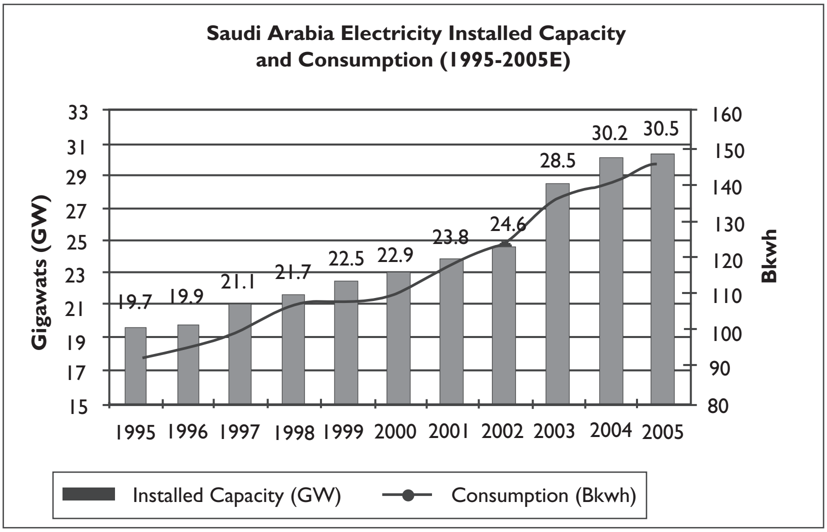


Figure 2.6.13 Historical changes in installed capacity of electricity in Saudi Arabia (EIA, 2008).

the national grid. For example, as part of the Khursaniya and Shaybah mega-projects, two cogeneration units with a combined capacity of 300 MW were installed. Also, a 380-MW plant is being constructed at Rabigh that will power the adjacent Sumitomo/Aramco petrochemical complex.

2.6.4.2 *Carbon dioxide emissions*

Outside the data given by U.S. Department of Energy on carbon dioxide emissions for Saudi Arabia (EIA, 2008; Fig. 2.6.14), not much is available. Saudi Arabia ranks 20 (U.S.A. is on the top with rank 1, accounting for 22.2% of world's total).

2.6.5 Future scenario

Saudi Aramco's plans to increase marketed oil production in the medium term hinges on the maintenance and expansion of the petroleum pipeline network, export facilities, and shipping capacity. Saudi Oil demand is expected to rise by eight to 10 percent through 2010, mostly in the area of electricity and NGLs for petrochemical production. In order to free up petroleum for export, Saudi Arabia continues to explore for natural gas resources throughout the country.

Saudi Arabia's long-term goal is to further develop its lighter crude reserves including the Shaybah field, located in the remote Empty Quarter (Rub al-Khali) area bordering the United Arab Emirates, the Abu Hadriya, Fadhili and Khursaniya (AFK) fields and the super giant Khurais. Although the Ministry has only committed to increasing capacity to 12.5 million bbl/d by 2009, potential increases to 15 million bbl/d capacity (post-2011) were discussed at a summit in Jeddah in June 2008.

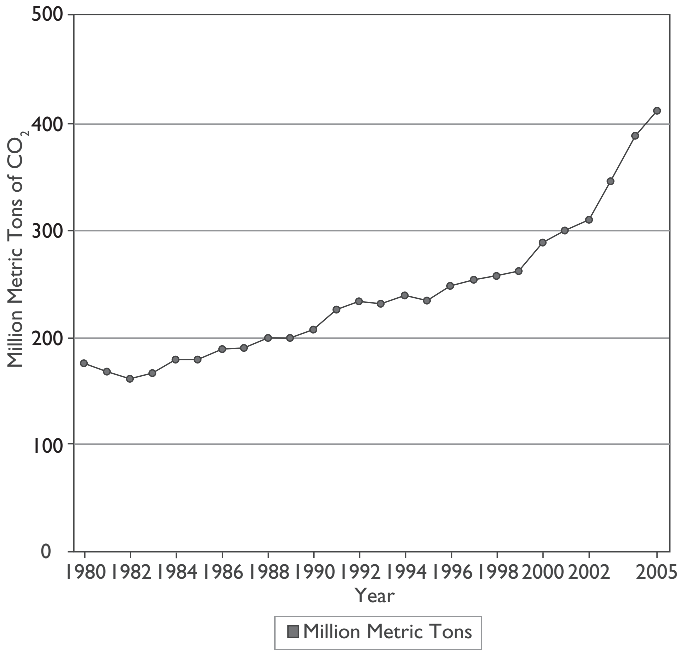


Figure 2.6.14 Historical changes in carbon dioxide emissions in Saudi Arabia (EIA, 2008).

SaudiAramco continues aggressive plans to increase crude oil production capacity despite some recent delays. Table 2.6.10 indicates planed production capacity increases through 2012.

The Shaybah field is the largest oil field in the world that has been developed in the past two decades. In addition to oil, Shaybah has a large natural gas "cap" (associated gas), with estimated reserves of 25 trillion cubic feet (TCF). Gas production of 880 million cubic feet per day (Mcf/d) is re-injected. It is reported that possible gas recovery project could be implemented within 5 or 6 years, potentially for use in petrochemical production. In January 2008, Saudi Aramco announced that the Khursaniyah development would be delayed. The development of the Khurais field will give Saudi Arabia the distinction of being the only oil producer to have two "super giant" fields (including Ghawar), those which produce more than 1 million bbl/d of crude oil. The Manifa expansion, expected in 2011, will replace capacity lost to natural declines (Jaffe and Elsass, 2007; Fig. 2.6.15) and support the capacity expansion. Some sources indicate that projects at Shaybah, Nuayyim and Khurais – like the AFK fields – projects could slip on their original deadlines by three to six months. Trade press recently reported that Khurais could come on in two phases, 800,000 bbl/d in 2009 and the rest in 2010.

In addition to these planned capacity increases, Saudi Aramco has stated that it will also conduct additional drilling at existing fields in order to help compensate for the natural declines from the mature fields. In April 2008, Saudi Aramco also

Table 2.6.10 Installed electricity capacity and consumption in Saudi Arabia (EIA, 2008).

	Upstrem natural gas projects (2004–2012)				
	Field	*Area*	*Projected capacity addition (bcf/d)*	*Expected online*	*Notes*
Non-Associated	Karan	Offshore Khuff Region	1.5	2012	Saudi Arabia's largest gas project currently in development. Recently increased production expection by 0.5 bcf/d
	Ghazal	Onshore	0.13	2008	Producing approximately 0.27 bcf/d
	Midrikah	Onshore	Unknown	TBA	
	Fazran	Onshore	Unknown	TBA	In testing
Associated	Qatif/Abu Safa'a	Onshore	0.40	2004	
	Haradh	Onshore	0.25	2005	
	Khurais	Onshore	0.3	2009	
	Khursaniyah	Onshore	0.3	2008	
	Manifa	Offshore	0.12	2011	

Sources: Dow Jones, Reuters, Oil Daily, Saudi Aramco, Global Insight, MEES.

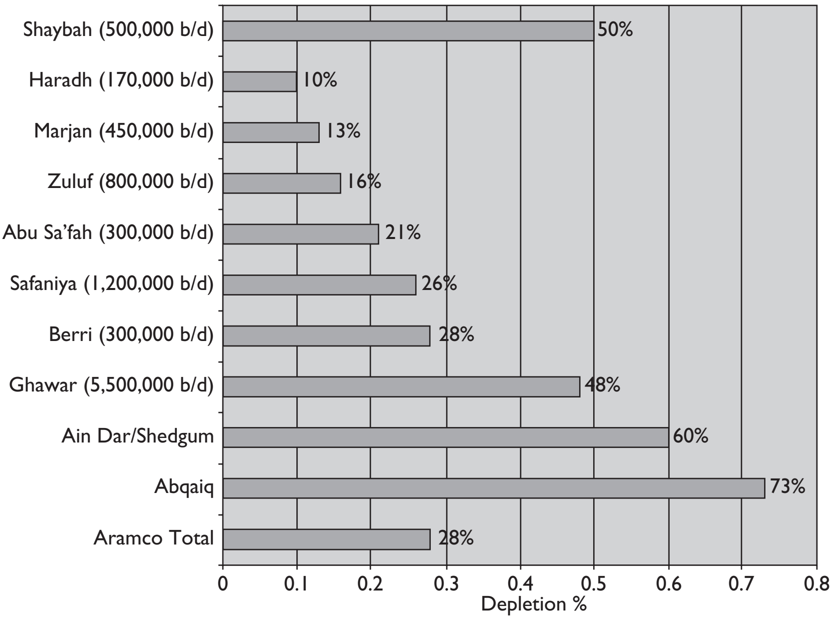


Figure 2.6.15 Depletion rates for different oil fields in Saudi Arabia (Jaffe and Elsass, 2007).
Source: Saudi Aramco.

announced a five-year plan beginning in 2009, to rapidly increase drilling exploration and investment in the oil sector. The plan includes increasing planned drilling by a third, to around 250 wells, with a priority in offshore area. However, increases in capacity development beyond the announced remain uncertain. Saudi Arabia's Minister of Oil, Ali al-Naimi said in April 2008, that the "country was confident that it had enough oil to meet expected demand for another 50 years." In 2007, the Saudi Aramco Annual Review reported new oil discoveries at Mabruk and Dirwazah, in the Eastern Province. The Mabruk-1 well, the first discovery in the Hadriya reservoir south of Ghawar, produced 5,600 bbl/d of Arabian Heavy with 2 MCF/d of natural gas. The Dirwazah-1 well produced approximately 5,569 bpd of Arabian Light) with 2.8 million Mcf/d of gas.

One challenge the Saudis face in achieving their strategic vision to add production capacity is that their existing fields experience, reportedly on average, 6 to 8 percent annual "decline rates" (as reported by *PlattsOilgram in 2006*) in existing fields, meaning that the country needs around 700,000 bbl/d in additional capacity each year just to compensate for natural decline. Decline estimates for Saudi Arabia vary widely, however. The Ministry of Petroleum maintains that decline rates in Saudi Arabia are around 2 percent annually. Saudi Aramco, Saudi Arabia's national oil company, estimates that the average total depletion for Saudi oil fields is 29 percent, with Abqaiq (the oldest) 74 percent depleted, the giant Ghawar field having produced 48 percent of its proven reserves and the younger Shaybah, just 5 percent depleted. Aramco also contends that Saudi oil reserves are likely under estimated, not overestimated, although some analysts have disputed Aramco's optimistic assessments of Saudi oil reserves and future production. Minister Al-Naimi has refuted these contrarian arguments, and stated that Saudi Arabia could add as much as 200 billion barrels of oil to proven reserves after the extended period of investment and exploration. In order to stave off decline, wells are undergoing reservoir management and rehabilitation projects, including the installation of Smart Well® technologies.

To meet growing domestic needs, in November 2006, the Petroleum Ministry and Saudi Aramco announced a $9-billion strategy to add 50 TCF of non-associated reserves between 2006 and 2016 through new discoveries (and potentially another 50 TCF of associated reserves). In order to free up petroleum for export, all current and future gas supplies (except natural gas liquids) reportedly remain earmarked for use in domestic industrial consumption and desalination. According to the 2007 Saudi Aramco Annual Review, the company has increased the rate of exploration, drilling 73 development and exploratory wells in that year, as compared to 35 in 2006 and 20 in 2005. Some 300 development and 70 exploratory wells are reportedly planned by 2010. According to Aramco, exploration and development will also commence in non-producing areas such as the Red Sea, northern and western Saudi Arabia, and the Nafud basin, north of Riyadh. The Saudi domestic natural gas market, traditionally the sole domain of Saudi Aramco, is slowly being opened to private investment both in exploration and distribution, and increasing competition in the market. The backbone of the non-associated gas exploration strategy relies on foreign consortiums exploring for onshore gas and condensate (natural gas liquids) in the Rub al-Khali, which officials hope will produce some 2 Bcf/d by 2011, although success has been limited. No commercial discoveries of natural gas have been reported in the dozen or more wells drilled by the consortia. Although limited gas discoveries have been made, the artificially low set price for domestic sales may render exploitation uneconomical.

The South Rub al-Khali Company (SRAK), a consortium of Saudi Aramco and Royal Dutch/Shell, is investing an estimated $2 billion in exploring more than 81,000 sq-miles in two separate concession blocks (Blocks 5–9 and 82–85). The concessions surround the Shaybah and Kidan oil fields, abutting Oman and the UAE, and the Saudi-Yemeni border respectively. The consortium originally aimed to sell 500 MMcf/d gas and condensate to the Ministry starting in 2009. SRAK drilled its first exploration well of three in July 2006, (Isharat-1, a wildcat), and is now drilling its first in the Kidan North Fields, although any finds are expected to have high sulfur levels. In the SRAK consortium, Shell and Saudi Aramco are equal shareholders, following the withdrawal of Total in February 2008, due to rising costs.

The Saudi Aramco development plan calls for a $70-billion investment in increasing domestic refining capacity to 3 million bbl/d and international holdings by at least 1–2 million bbl/d by 2011 (Saudi Aramco, 2006), particularly in an effort to meet requirements of the fast-growing Asian market (Table 2.6.11). One of Saudi Aramco's strategies includes increasing private investment through joint ventures in refining activities, for which MOUs were signed on two projects in 2006 (Jubail and Yanbu'). As part of the privatization program, 30 percent of shares of new refineries will be offered to the public. The proposed facility at Jizan, which would be Saudi Arabia's first privately owned an operated refinery, is said to be under consideration for investment by the Chinese. Aramco has previously partnered with ExxonMobil at their 400,000-bbl/d facility at Yanbu' and with Shell at the existing 305,000-bbl/d facility at Jubail. In January 2004, Russia's Lukoil won a tender to explore for and produce non-associated natural gas and natural gas liquids in the Saudi Empty Quarter in Block A (11,000 sq miles), near Ghawar, as part of an 80/20 joint venture with Saudi Aramco, known as Luksar. In 2007, Luksar reported a "speculative" find of around 620 million bbl of unidentified hydrocarbon reserves (reported to include oil equivalent and condensate) in the Tukhman-3 area, although any oil finds would fall outside the consortium's development rights. At the same time, China's Sinopec won a tender for gas exploration and production in Block B (15,000 sq miles). Sino Saudi Gas, a venture of Sinopec and Aramco, has drilled at least three wells and in December 2007, reported the first natural gas find in the area (Sheeh-2) although the quantity is unconfirmed and geology reported to be complex. China and Saudi Arabia recently signed a MOU which indicates that imports could rise to 1 million bbl/d by 2010. It has been reported that GAIL, a state-owned oil and gas company from India, is in talks with Lukoil to buy a stake in the joint venture. Finally, the Eni-Repsol YPF-Aramco consortium, EniRepSa Gas, was granted a license to operate in Block C (52,000 sq km), and drilled its first well in September 2006. The consortia have reported trace finds of natural gas. The consortia have some 27 wells planned in total by 2009, when the five-year exploration contracts expire. The consortia have reportedly requested concession exploration extensions, and in May 2008, SRAK received an 18-month extension 2010. The development contracts cover

Table 2.6.11 Planned upstream natural gas projects in Saudi Arabia (EIA, 2008).

Proposed refinery additions and expansion (2005–2013)

Project	*Announced completion date*	*Capacity increase (MMbbl/d)*	*Total capacity (MMbbl/d)*	*Aramco partners*	*Notes*
Domestic					
PetroRabigh JV (expansion)	2008 (Q4)	60	460	Sumitomo Chemical (Japan)	Integrated oil refinery and petrochemical complex. Upgrade to shift product mix away from low-value heavy products towards gasoline and kerosene. Second upgrade (2010) to bring capacity up to 825,00 bbl/d has been proposed.
Jubail JV	2012 (Q4)	400	400	Total	Export-oriented, heavy conversion.
Ras Tanura	2012	400–400	400–440	None	For domestic consumption. Part of existing Ras Tanura refining complex, which will have a total capacity of approximately 950,000 bbl/d.
Yanbu' JV	2013	400	400	Conoco-Philips	Export-oriented, heavy conversion.
Jizan	TBD (2012/2013)	250–400	250–400	TBD	Proposed. Reported to go to bid in 2008.
Yanbu' (expansion)	2010/2011	100	330	None	Proposed. Reported to go to bid in 2008.
Overseas					
Fujian, China	2007	80	240	Sinopec –50% ExxonMobil 25%	First of two facilities in China. Combined refinery and petrochemical plant.
Fujian, China (expansion)	2009(Q1)	160			
Motiva-Port Arthur, TX (expansion)	2010	325	600	Shell	To be the largest U.S. refinery.

Source: Dow Jones, Reuters, Oil Daily, Saudi Aramco, Global Insight, MEES, PFC.

a 40-year period, except SRAK, which holds a 25 year contract. Constraints on obtaining rigs have also slowed the pace of exploration over the past two years.

Saudi Arabia has prioritized gas development outside the Empty Quarter and recent non-associated gas finds are promising. The Karan gas field, discovered in April 2006, is the largest gas deposit yet discovered in the offshore Khuff formation, some 100 miles north of Dhahran. Initial data shows at least eight gas-bearing structures in the Khuff region around the Karan reservoir containing an estimated 9 TCF of reserves. Of those, Karan alone is expected to produce some 1.5 BCF/d when it comes online in 2012. Reportedly the Riyadh Chamber of Commerce and Industry is planning a feasibility study with Russia's Stroytransgaz for the construction of another 7-Bcf/d domestic delivery system that will deliver gas from the Empty Quarter to customers in the east, central and western areas, and will include the construction of some 2000 miles of new pipeline. Construction hinges on a significant non-associated gas discovery in the Empty Quarter.

According to Saudi Aramco, the offshore Jana-6 and an extension of Karan (Karan-7) were the only major gas finds in 2007. Discoveries in 2006 included an earlier extension of the Karan field (Karan-6), with the potential to add 80 MCF/d to gas flows, and onshore, the Kassab-1 and the Zamalah wells in the Jauf Reservoir, which could add a combined 20 Mcf/d and more than 600 bbl/d of condensate. Finally, Najimaan-1 (Nujayman) reportedly has the potential production capacity in excess of 60 MCF/d of gas and 2000 bb/d of condensate, according to Aramco sources. Another large non-associated offshore natural gas field, Dorra (Durra), is located offshore near Khafji oil field in the Saudi-Kuwaiti Neutral Zone. Dorra development has been controversial since the late 1960s, however, because 70 percent is also claimed by Iran (called Arash). In addition, the maritime border between Kuwait and Iran remains undemarcated. Saudi Arabia reached an agreement with Kuwait in July 2000 to share Dorra output equally, although the Kuwaitis are reportedly trying to purchase the Saudi share. According to Saudi Aramco, the field is estimated to contain non-associated gas reserves of between 35 and 60 TCF of natural gas, and is under seismic study. The Kuwaiti Ministry of Oil has reported that the goal is to produce initially 600 MMCF/d from Dorra. Kuwait and Iran have intermittently discussed jointly developing the field, although production plans remain undisclosed.

Saudi Arabia currently has seven gas processing plants with a total gas production capacity of approximately 9.3 Bcf/d, including 1.1 million bbl/d of natural gas liquids (NGLs) and approximately 2,700 tons of sulfur at facilities Berri, Shedgum, Uthmaniyah and Hawiyah. According to statements made by Saudi Aramco, the country aims to process an estimated 13 Bcf/d by 2009 through additional facilities and capacity expansion. Mega-project plans are currently underway at Khursaniya, Hawiya, Ju'aymah, Yanbu' and Khurais. According to Saudi Aramco forecasts, natural gas demand in the kingdom is expected nearly to double to 14.5 billion cubic feet per day (Bcf/d) by 2030, up from an estimated 7.1 Bcf/d in 2007. The situation is exacerbated by the fact that the majority of gas fields in Saudi Arabia are "associated" with petroleum deposits, or found in the same wells as the crude oil, and plans to increase production of this type of gas remain linked to an increase in oil production. The majority of new natural gas discovered in the 1990s has been associated in light crude oil, especially in the Najd region south of Riyadh. For this reason, Saudi Arabia has concentrated efforts to locate non-associated gas pockets onshore and in offshore formations. According to Saudi Aramco, only 15 percent of Saudi Arabia has been "adequately explored for gas." Traditionally, the power and desalination sectors, followed by petrochemicals and steel manufacturing, have made up the majority of demand for natural gas in Saudi Arabia. Consumer demand for power generation is also growing, particularly in the summer months.

Saudi Arabia's power sector, including generation, transmission and distribution, has traditionally seen dominated by the partly state-owned Saudi Electricity Company. However, in July 2002, the Supreme Economic Council passed a resolution setting out a framework for private sector involvement in developing mega-scale integrated Independent Water and Power Projects (IWPPs), and since that time the sector has become increasingly liberalized. Saudi Arabia aims to attract private sector investment for up to 60 percent equity in IWPP projects, with the remainder split between Public Investment Fund (PIF) and the SEC. In March 2004, Saudi Arabia announced their plan to launch ten IWPPs by 2016, at a total cost of around $16 billion (although this is said to be increasing). The SEC has already approved six such mega-projects. The majority of the facilities will be in the Western parts of the country, drawing from the Red Sea.

The combined production capacity of the original four projects, which are under construction or in the bidding phase, will produce more than 7000 MW (at final capacity) of power and 600 million gallons of water daily. They will boost the total desalination capacity of the kingdom by 80 percent when the come online between 2009 and 2010. Also proposed is a 60-MW, 23-MMg/d Shuqaiq (III) extension.

Besides generation, Saudi Arabia also requires additional investment in power transmission. At present, around 10 percent of the Kingdom's population lacks access to the national power grid. Aramco estimates that creating a unified national grid may require laying more than 20,000 miles of additional power transmission and distribution lines on top of the existing 150,000 miles of lines. Saudi Arabia is also taking steps to interconnect their power grids with other Arab countries to benefit from differences in peak demand. The grids of the six Gulf Cooperation Council (GCC) countries are scheduled to be fully integrated by 2010. Saudi Arabia will take part in a linkup with Kuwait, Bahrain and Qatar by 2009. The US$1.2-billion first phase will include an overhead linkup to Kuwait and marine transmission infrastructure to Bahrain.

Throughout the kingdom, independent power projects (IPPs), which are not integrated with desalinization facilities, are also being tendered by the SEC, primarily to local contractors. According to the SEC, about 8000 MW of new capacity is currently under construction, 5200 MW of which are IPPs. The SEC is calling for ten percent of power generation to come from IPPs in the next decade. Three SEC-led IPPs are currently being planned include Rabigh (1200 MW, online 2012 or 2013), Riyadh-P11 (2000 MW, 2013 or 2014) and Al-Qurayyah (2000 MW, 2014 or 2015). The facilities will be built on a Build-Own-Operate (BOO) basis, and the SEC will be a partner. In addition, several large-scale electricity IPPs are still in the planning phases, including 1,725-MW expansions at Muzahimiyah, and Shubuk, and Riyadh-PP10.

Saudi Arabia's Water and Electricity Ministry (WEC) estimates that the country will require at least 35 Giga watts (GW) of additional power generating capacity by 2023–25 – more than double the 2005 estimate of installed capacity of 30.5 GW – at a cost of an estimated $120 billion. (According to the Saudi Electricity Company (SEC), capacity reached 35.9 MW in 2007). In addition, Saudi Arabia's state-owned Saline Water Conversion Corp. (SWCC) has estimated that through 2020, the country will need to spend at least $50 billion on water projects, many integrated with new power generation capacity, in order to meet the Kingdom's equally rapidly growing water demand. Most of this money is slated to come from the private sector, including foreign investors. Feedstock for planned power capacity increases was originally expected to be natural gas and/or combined cycle. However, many new facilities may be crude-oil fired due to constraints on domestic natural gas supplies. A royal decree issued in the spring of 2006, requires that all future coastal power plants utilize crude feedstock at a set price of $0.46 per million BTU. According to a June 2008 report by Facts Global Energy, some 200,000 to 250,000 bbl/d of crude is being burned directly for power generation. All of Saudi Arabia's electric power generation is thermal.

2.7 RUSSIA – COUNTRY CASE STUDY

2.7.1 Introduction

Russia's economy is heavily dependent on oil and natural gas exports. Russia holds the world's largest natural gas reserves, the second largest coal reserves, and the eighth largest oil reserves. Russia is also the world's largest exporter of natural gas, the second largest oil exporter and the third largest energy consumer. In order to manage windfall oil receipts, the government established a stabilization fund in 2004. By the end of 2007, the fund was expected to be worth $158 billion, or about 12% of the country's nominal GDP, of which, the fuel sector accounts for about 20.5% of GDP, down from around 22% in 2000. According to IMF and World Bank estimates, the oil and gas sector generated more than 60% of Russia's export revenues (64% in 2007), and accounted for 30% of all foreign direct investment (FDI) in the country. In 2007, Russia's real gross domestic product (GDP) grew by approximately 8.1%, surpassing average growth rates in all other G8 countries, and marking the country's seventh consecutive year of economic expansion. Russia's economic growth over the past seven years has been driven primarily by energy exports, given the increase in Russian oil production and relatively high world oil prices during the period. Internally, Russia gets over half of its domestic energy needs from natural gas, up from around 49 percent in 1992 (Beral, 2008; Fig. 2.7.1). Since then, the share of energy use from coal and nuclear has stayed constant, while energy use from oil has decreased from 27% to around 19%. Kremlin policy makers continue to exhibit an inclination to advance the state's influence in the energy sector. Taxes on oil exports and extraction are still high, and Russia's state-influenced oil and gas companies are obtaining controlling stakes in previously foreign-led projects. State-owned export facilities have grown at breakneck pace, while private projects have progressed more slowly or have been met with roadblocks by state-owned companies or by various government agencies.

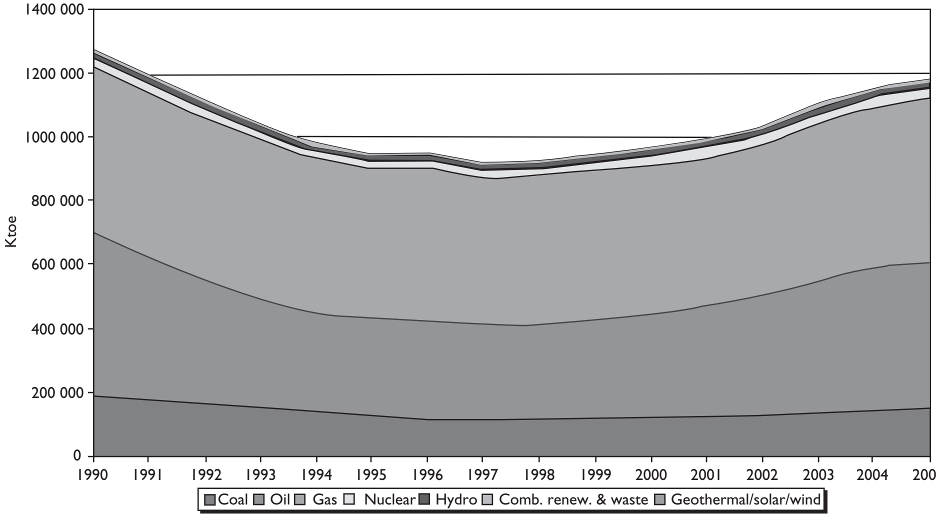


Figure 2.7.1 Evolution of total production of energy in Russia from 1990 to 2005 (IEA, 2007) (See colour plate 12).

2.7.2 Distribution, reserves and resources

As mentioned earlier (see Section 2.6.2 and Figures 2.6.2 and 2.6.3), the second cluster in the geographic distribution of the world's 932 giant oil and gas fields is located in the West Siberian Basin in Russia (Mann et al., 2007; USGS, 2008a; Fig. 2.7.2). In the systematic global assessment of oil and natural gas resources by the U.S. Geological Survey (Ulmishek, 2003; USGS, 2000), Russia forms the main part of Region 1 (former Soviet Union), in which West Siberian Basin Province and Timan-Pechora Basin Province contain most of the petroleum deposits. Russia has proven oil reserves of 60 billion barrels (USGS, 2008b; Fig. 2.7.3), most of which are located in Western Siberia, between the Ural Mountains and the Central Siberian Plateau.

Two TPS of the West Siberian basin are exceptionally rich in hydrocarbons and contain the largest share of undiscovered resources in Region 1. The northern West Siberian Mesozoic TPS contains nearly one-quarter of the original gas reserves of the world in a relatively small area. The results of the USGS assessment indicate that the largest amount of undiscovered hydrocarbon resources, both oil and gas, is concentrated in the richest petroleum province, the West Siberian basin, despite the significant exploration maturity of this province. At the mean level, combined resources of three TPS in the basin constitute 47.6 percent of oil and 38.7 percent of gas resources of all petroleum provinces assessed in the FSU. For oil plus NGL and both free and associated gas these numbers are 44.3% and 38.9%, respectively. The largest portion of undiscovered oil (77.7%) occurs in the principal reservoirs of the Bazhenov-Neocomian TPS. Only 13.6% of undiscovered oil is expected in much less explored pre-Upper Jurassic rocks of the Togur-Tyumen TPS mainly because of the commonly poor quality of reservoir rocks. Undiscovered gas resources are almost entirely placed in the northern TPS of the West Siberian basin, especially offshore in

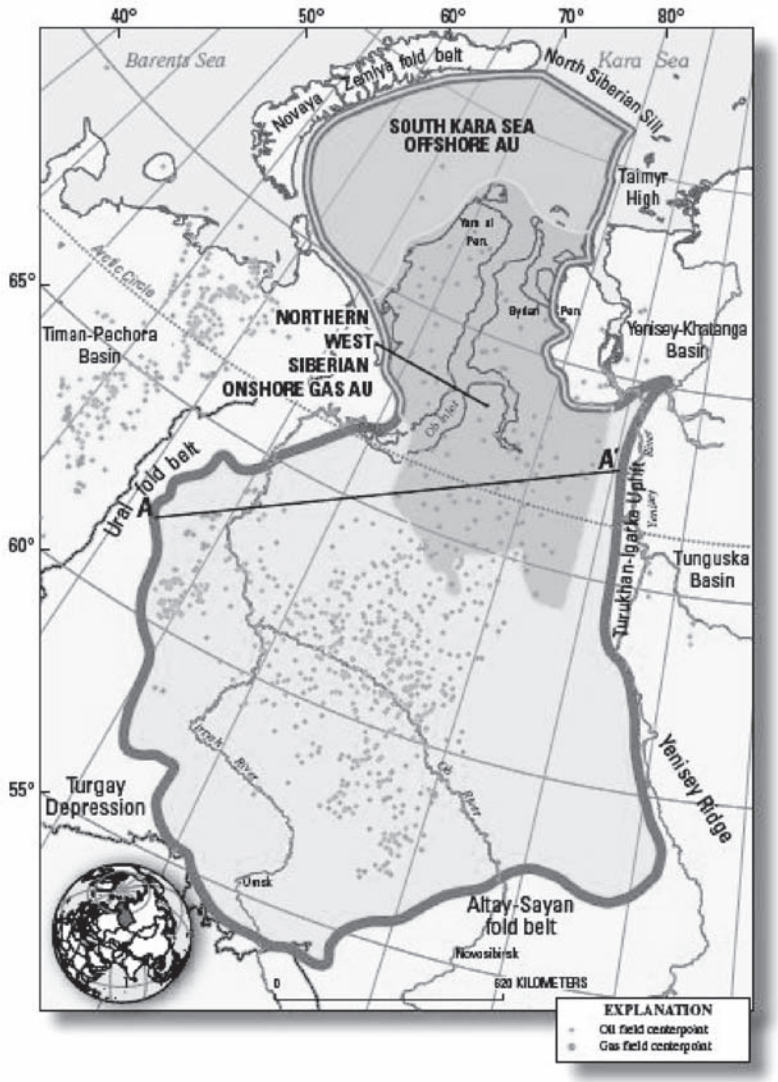


Figure 2.7.2 Distribution of oil and gas fields in the West Siberian Basin in Russia (USGS, 2008a).

the South Kara Sea. Compared with the previous USGS resource assessment (Masters et al., 1998), the amount of oil resources of the West Siberian basin determined from the USGS (2000) assessment is similar. The results of the quantitative assessment of undiscovered, technically recoverable, conventional oil and gas resources in that part of the Northern West Siberian Mesozoic Composite TPS north of the Arctic Circle are given in Table 2.7.1. The total estimated means for undiscovered conventional oil and gas resources are 3,659 million barrels of oil (MMBO), 651.5 trillion cubic feet of natural gas (TCFG), and 20,329 million barrels of natural-gas liquids (MMBNGL).

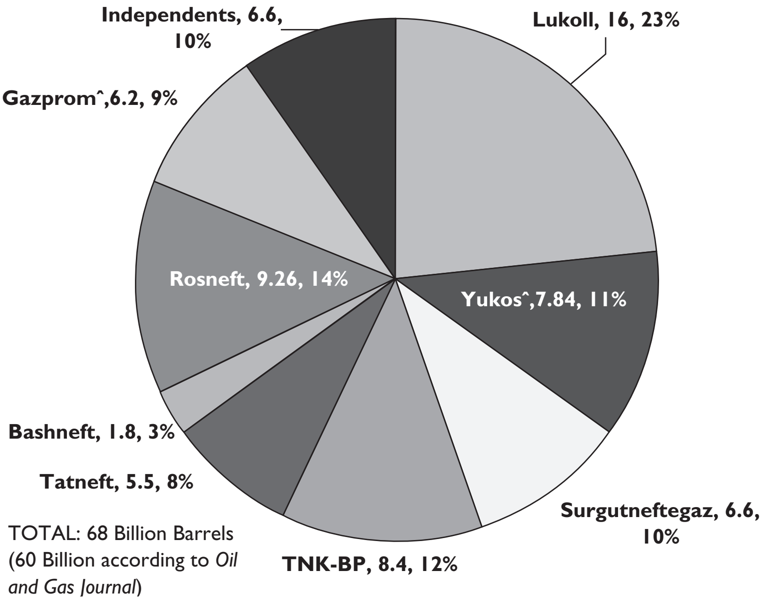


Figure 2.7.3 Shares of Russia's proven oil reserves controlled by different companies (EIA, 2008).

Of these volumes, the Northern West Siberian Onshore Gas AU accounts for 1,152 MMBO, 29,277 BCFG, and 850 MMBNGL, and the South Kara Sea Offshore AU accounts for 2,507 MMBO, 622,222 BCFG, and 19,479 MMBNGL.

The second most important petroleum province is the Timan-Pechora basin (Fig. 2.7.4), which is sparsely drilled in its northern areas where significant additional potential lies for undiscovered resources of both oil and gas. Several studies have presented geological summaries of the Timan-Pechora Basin Province and the potential for its remaining oil and gas resources (for example, Ulmishek, 1982, 2000; Lindquist, 1999; Table 2.7.2). Geologically, the Timan-Pechora Basin Province is a triangular-shaped cratonic block bounded by the northeast-southwest trending Ural Mountains and the northwest-southeast trending Timan Ridge. The northern boundary is shared with the South Barents Sea Province. The Timan-Pechora Basin Province has a long history of oil and gas exploration and production. The first field was discovered in 1930 and, after 75 years of exploration, more than 230 fields have been discovered and more than 5,400 wells have been drilled. This has resulted in the discovery of more than 16 billion barrels of oil and 40 trillion cubic feet of gas.

The large TPS of the North Caspian basin was assessed to contain the greatest amount of undiscovered oil resources. However, compared with the previous USGS assessment (Masters et al., 1997), the amount of undiscovered oil resources of the North Caspian basin decreased almost two-fold, from 45.4 to 23.3 BBO. The amount of undiscovered gas in this TPS decreased even more significantly from 261.2 to 74.5 TCF. This decrease reflects a continuous lack of success in discovering giant and large fields in the basin during about the last 15 years.

Table 2.7.1 Estimates of oil and gas resources in the West Siberian Basin Petroleum System (USGS, 2008a).

Total Petroleums Systems (TPS) and Assessment Units (AU)	*AU probability*	*Field type*	*Largest expected oil field size*	*Total undiscovered resources*											
				Oil (MMBO)				*Gas (BCFG)*				*NGL (MMBNGL)*			
				F95	*F50*	*F5*	*Mean*	*F95*	*F50*	*F5*	*Mean*	*F95*	*F50*	*F5*	*Mean*
Northern West Siberian Mesozoic Composite TPS															
Northern West Siberian Onshore Gas AU	1	Oil	431	223	901	2,930	1,152	1,241	5,304	17,744	6,859	25	109	369	142
		Gas	5,560					6,242	18,831	50,642	22,418	194	594	1,613	708
South Kara Sea Offshore AU	1	Oil	712	572	2,053	6,023	2,507	3,183	12,064	36,779	14,933	64	248	763	308
		Gas	189,354					154,681	513,304	1,372,510	607,289	4,799	16,000	44,090	19,171
Total Conventional Resources							3,659				651,439				20,329

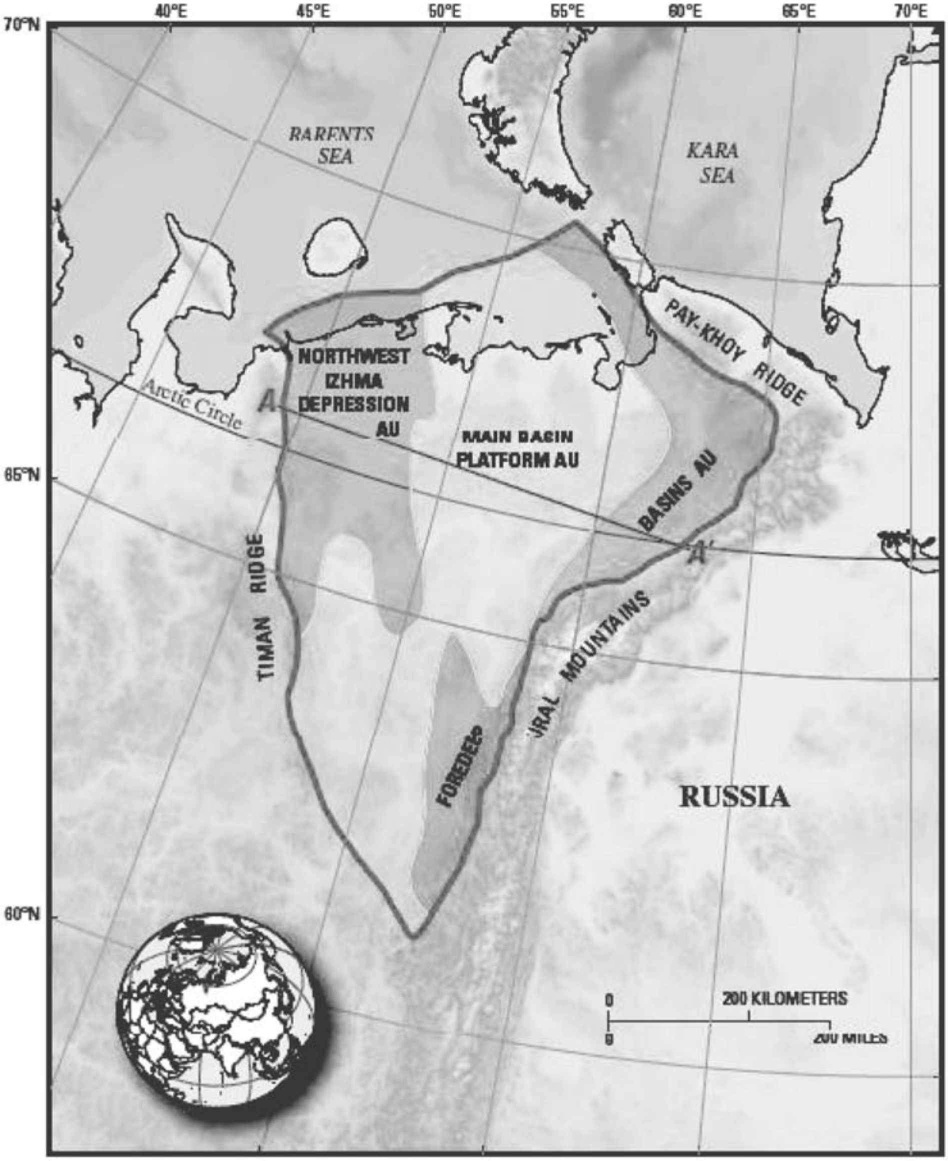


Figure 2.7.4 Location of the Timan-Pechora Basin in Russia (USGS, 2008b).

2.7.3 Production and exports

2.7.3.1 Production

Oil: In the 1980s, the Western Siberia region, also known as the "Russian Core," made the Soviet Union a major world oil producer, allowing for peak production of 12.5 million barrels per day in total liquids in 1988. Following the collapse of

Table 2.7.2 Estimates of oil and gas resources in the Timan-Pechora Basin Petroleum System (USGS 2008b).

Total Petroleums Systems (TPS) and Assessment Units (AU)	*AU probability*	*Field type*	*Largest expected field size*	*Total undiscovered resources*											
				Oil (MMBO)				*Gas (BCFG)*				*NGL (MMBNGL)*			
				F95	*F50*	*F5*	*Mean*	*F95*	*F50*	*F5*	*Mean*	*F95*	*F50*	*F5*	*Mean*
Domanik-Paleozoic TPS															
Northwest Izhma Depression AU	0.02		Not quantitatively assessed												
Main Basin Platform AU	1	Oil	549	762	1,504	2,852	1,613	918	1,942	3,975	2,131	20	45	95	50
		Gas	1,404					895	2,476	6,143	2,859	19	54	190	64
Foredeep Basins AU	0.54	Oil	163	0	0	234	55	0	0	327	72	0	0	7	2
		Gas	1,946					0	3,658	12,094	4,000	0	74	272	88
Total Conventional Resources							1,668				9,062				204

Table 2.7.3 Energy (in thousand tons of oil equivalents – KTOE – on a net calorific value basis) balances for Russia (IEA, 2008).

	1997	*1998*	*1999*	*2000*	*2001*	*2002*	*2003*	*2004*	*2005*	*2006*	*2007*
Petroleum (Thousand barrels per day)											
Total oil prod.	6101.09	6069.67	6312.32	6723.64	7159.73	7658.89	8534.78	9273.77	9512.98	9676.57	9875.77
		5854	6078.95	6479.2	6917	7408.17	8132.2	8804.71	9043.08	9247.21	9437.06
Consumption	2562.48	2488.61	2537.62	2578.5	2590.23	2636.41	2681.86	2750.81	2757	2810.76	2858
Exports/Imports	3538.61	3581.06	3774.69	4145.14	4569.50	5022.48	5852.92	6522.96	6755.98	6865.81	7018
		24	89	72	90	210	254	298	410	369	413
Refinery Capacity	6733	6869	6745	6673	5435	5435	5435	5435	5433	5341	5339
Proved Reserves (Billion Barrels)	48.573	48.573	48.573	48.573	48.573	48.573	60	60	60	60	60
Natural Gas (Billion Cubic Feet)											
Production	20168.4	20867.6	20825.3	20631	20511	21026.6	21768.2	22386.2	22622.8	23166.6	NA
Consumption	13433.8	14044.8	14013	14129.5	14412.1	14567.4	15291.4	16022.4	16153.1	16598.1	NA
Exports/Imports	6734.6	6822.9	6812.3	6501.5	6098.9	6459.1	6476.8	6363.8	6462.6	NA	NA
Proved Reserves	1,700,000	1,700,000	1,700,000	1,700,000	1,700,000	1,680,000	1,680,000	1,680,000	1,680,000	1,680,000	1,680,000
Electricity (Billion Kilowatthours)											
Net Generation	796	787.8	799.9	833	843.3	847.1	869.1	886.3	904.4	NA	NA
Net Consumption	691.9	676.6	689.6	717.3	721.8	731.4	745.2	766.1	779.4	NA	NA
Capacity (GWe)	207.6	205.7	203.7	203.5	204.7	205.6	214.4	215.5	217.2	NA	NA
Total Primary Energy (Quadrillion Btu)											
Production	40.6	40.9	42.6	43.6	44.8	46.1	49.1	51.6	52.7	NA	NA
		26.2	27.2	27.7	28	28.2	29.1	29.9	30.3	NA	NA
Energy Intensity	19148.6	20328.5	19908.1	18395.3	17665.9	16992.6	16323.3	15698.4	14935.3	NA	NA
Carbon Dioxide Emissions (Million Metric Tons of CO_2)											
Total	1482	1482.6	1558.5	1580.2	1569.5	1569.4	1627.4	1668.7	1696	NA	

Table 2.7.4 Depletion of Russia's largest producing oil fields (IHS, 2008).

	Production			
Field	*2005*	*2006*	*Online date*	*Depletion**
Samotlor	868	844	1964	73%
Feorovo-Surgutskoye	482	433	1973	70%
Priobskoye	466	552	1989	14%
Romashkinskoye (Tatarstan/Samara)	300	301	1949	85%
Tevlinsko-Russkinskoye	247	223	1986	49%
Ust-Balyk-Mamontovskoye	241	242	1964	85%
Tyanskoye	214	264	1995	31%
Pokachevsko-Uryevskoye	190	178	1977	63%
Sugmutskoye	190	186	1995	67%
Vatyeganskoye	164	167	1984	37%
Malo-Balykskoye	158	165	1984	41%
Krasnoleninskoye	123	139	1985	13%
Povkhovskoye	116	122	1978	99%
Pravdinsko-Salymskoye	114	124	1968	29%

* Depletion is defined as Cumulative Production/Recoverable Oil Reserves (P + P).

Source: Cited with permission from IHS Energy, Feb. 2008: www.ihsenergy.com

the Soviet Union in 1991, Russia's oil production fell precipitously, reaching a low of roughly 6 million bbl/d, or around one-half of the Soviet-era peak (Table 2.7.3). Several other factors have caused the decline, including the depletion of the country's largest fields (Table 2.7.4) due to state-mandated production surges. A turnaround in Russian oil output began in 1999. Many analysts have attributed the rebound in production to the privatization of the industry following the collapse of the Soviet Union. Higher world oil prices (oil prices tripled between January 1999 and September 2000), the usage of technology that was standard practice in the West, and the rejuvenation of old oil fields also helped raise production levels. By 2005 Russian total liquids production averaged almost 9.5 million BBL/d (9 million BBL/d of which was crude oil). These production levels have made Russia the world's second largest producer of crude oil, behind only Saudi Arabia.

With production of 9.8 million bbl/d of liquids (not including oil products; Fig. 2.7.5) and consumption of roughly 2.8 million bbl/d, Russia exported (in net) around 7 million bbl/d (Fig. 2.7.6). According to official Russian statistics, roughly 4.4 million bbl/d of this total is crude oil. Over 70 percent of Russian crude oil production is exported, while the remaining 30 percent is refined locally. Crude oil exports via pipeline fall under the exclusive jurisdiction of Russia's state-owned pipeline monopoly, Transneft.

Natural Gas: Russia holds the world's largest natural gas reserves, with 1,680 trillion cubic feet (TCF) – nearly twice the reserves in the next largest country, Iran. Accordingly, Russia is the world's largest natural gas producer (22.4 TCF), as well as the world's largest exporter (7.1 TCF). However, Russia's natural gas industry has not been as successful as its oil industry, with both natural gas production and

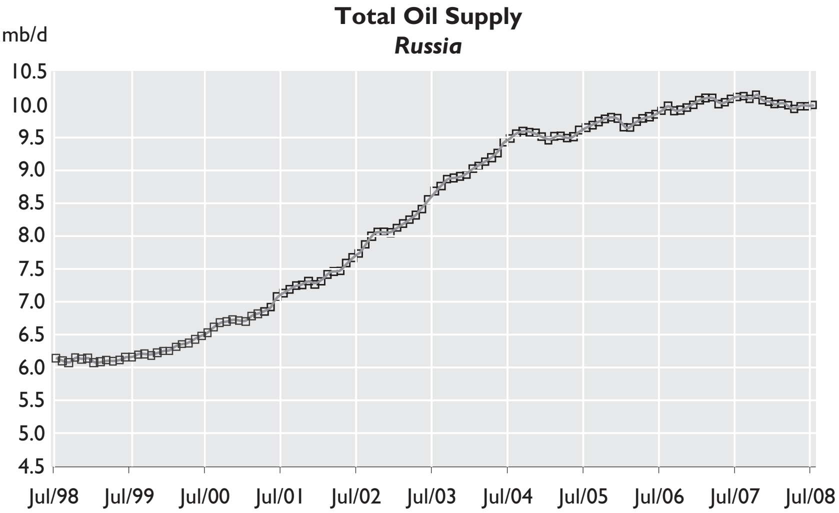


Figure 2.7.5 Monthly oil supply during the past decade in Russia (EIA, 2008).

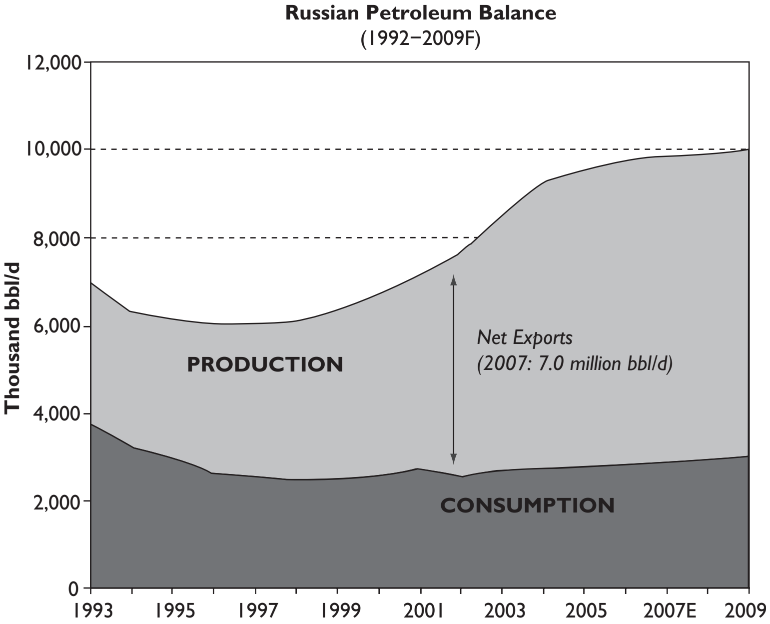


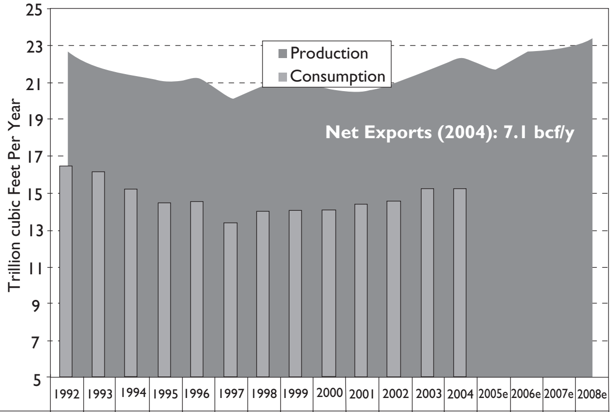
Figure 2.7.6 Russian petroleum balance (1993–2009) (EIA, 2008).

Sources: EIA: International Petroleum Monthly. Short Term Energy Outlook (Forecast).

consumption remaining relatively flat since independence (Fig. 2.7.7). Moreover, Gazprom's natural gas production forecast calls for only modest growth (about 1.3%) in 2008. Russia's natural gas sector has been stunted primarily due to aging fields, state regulation, Gazprom's monopolistic control over the industry, and insufficient export pipelines. Three major fields (called the 'Big Three') in Western Siberia – Urengoy, Yamburg, and Medvezh'ye – comprise more than 70% of Gazprom's total natural gas production, but these fields are now in decline. Although the company projects increases in its natural gas output between 2008 and 2030, most of Russia's natural gas production growth will come from independent gas companies such as Novatek, Itera, and Northgaz.

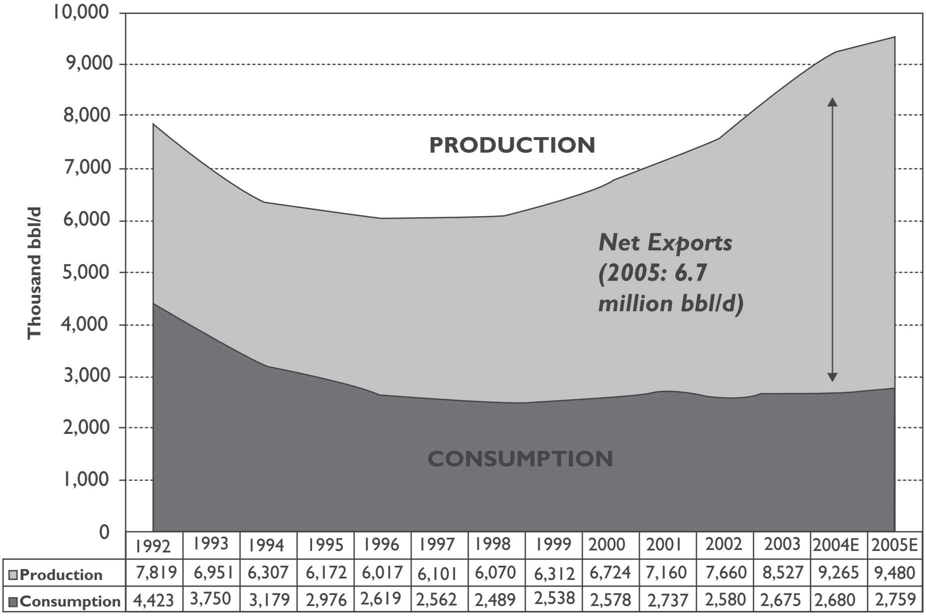
2.7.3.2 Exports

During 2007, Russia exported almost 4.4 million bbl/d of crude oil, and over 2 million bbl/d of oil products. Over 70 percent of Russian crude oil production is sent directly abroad for export, while the remaining 30 percent is refined locally. Approximately 1.4 million bbl/d of Russia's oil exports are sent via the multiple-branch Druzhba pipeline to Belarus, Ukraine, Germany, Poland, and other destinations in Central and Eastern Europe (including Hungary, Slovakia, and the Czech Republic). The remaining crude oil exports are sent to maritime ports in the Black Sea and Baltic Sea and are sold on world markets. Because of higher world oil prices recently, almost 170,000 bbl/d of Russia's oil is transported via railroad. Most of Russia's product exports consist of fuel oil and diesel fuel, which are used for heating in European countries and, on a very small scale, in the United States. Although Russia produces almost 7 million BBL/d of liquids (in net) for export, only about 4 million BBL/d can be transported by major trunk pipelines; the rest must be shipped by rail and river routes. Most of the 4 million bbl/d transported



	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005e	2006e	2007e	2008e
■ Production	22.6	21.8	21.5	21.0	21.2	20.2	20.9	20.8	20.6	20.5	21.0	21.8	22.4	21.7	22.7	22.8	23.4
■ Consumption	16.5	16.2	15.2	14.5	14.5	13.4	14.0	14.0	14.1	14.4	14.6	15.3	15.3				

Figure 2.7.7 Annual production and consumption of gas (1992–2009) for Russia (EIA, 2008).



	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004E	2005E
▫Production	7,819	6,951	6,307	6,172	6,017	6,101	6,070	6,312	6,724	7,160	7,660	8,527	9,265	9,480
■Consumption	4,423	3,750	3,179	2,976	2,619	2,562	2,489	2,538	2,578	2,737	2,580	2,675	2,680	2,759

Figure 2.7.8 Net exports Russian gas (1992–2005) (EIA, 2008).

via alternative routes are petroleum by-products (Fig. 2.7.8), which includes some intrastate transport. However, all of these alternate methods of exporting oil are much more costly than shipment via pipeline and could become less economical if world oil prices fall.

Until 1980s, the majority of Russia's natural gas exports were sent to customers in Eastern Europe (Fig. 2.7.9). But since the mid 1980's, Russia began looking to diversify its export options. Russia continues to export significant amounts of natural gas to customers in the Commonwealth of Independent States (CIS). In addition, Gazprom (through its subsidiary Gazexport) has shifted much of its natural gas exports to serve the rising demand in countries of the EU, as well as Turkey, Japan, and other Asian countries (Table 2.7.5). Russian natural gas exports rose during 2004 from previous years, but the Russian Ministry of Energy expects natural gas exports to grow at a slower rate. Last year, Russia exported approximately 7.1 TCF of natural gas. In recent months, Russia insisted on being paid higher prices for its natural gas exports to neighboring CIS countries. Even though Russia has used the threat of a cutoff to demand higher natural gas prices in recent years, this was the first time that a supply disruption has affected flows to Europe. Eventually, Russia's natural gas company agreed to a sell its natural gas to RosUkrEnergo, a trading company that also imports natural gas from Central Asia. In January 2006, Ukraine signed a five-year agreement to buy 580 BCF of natural gas from RosUkrEnergo.

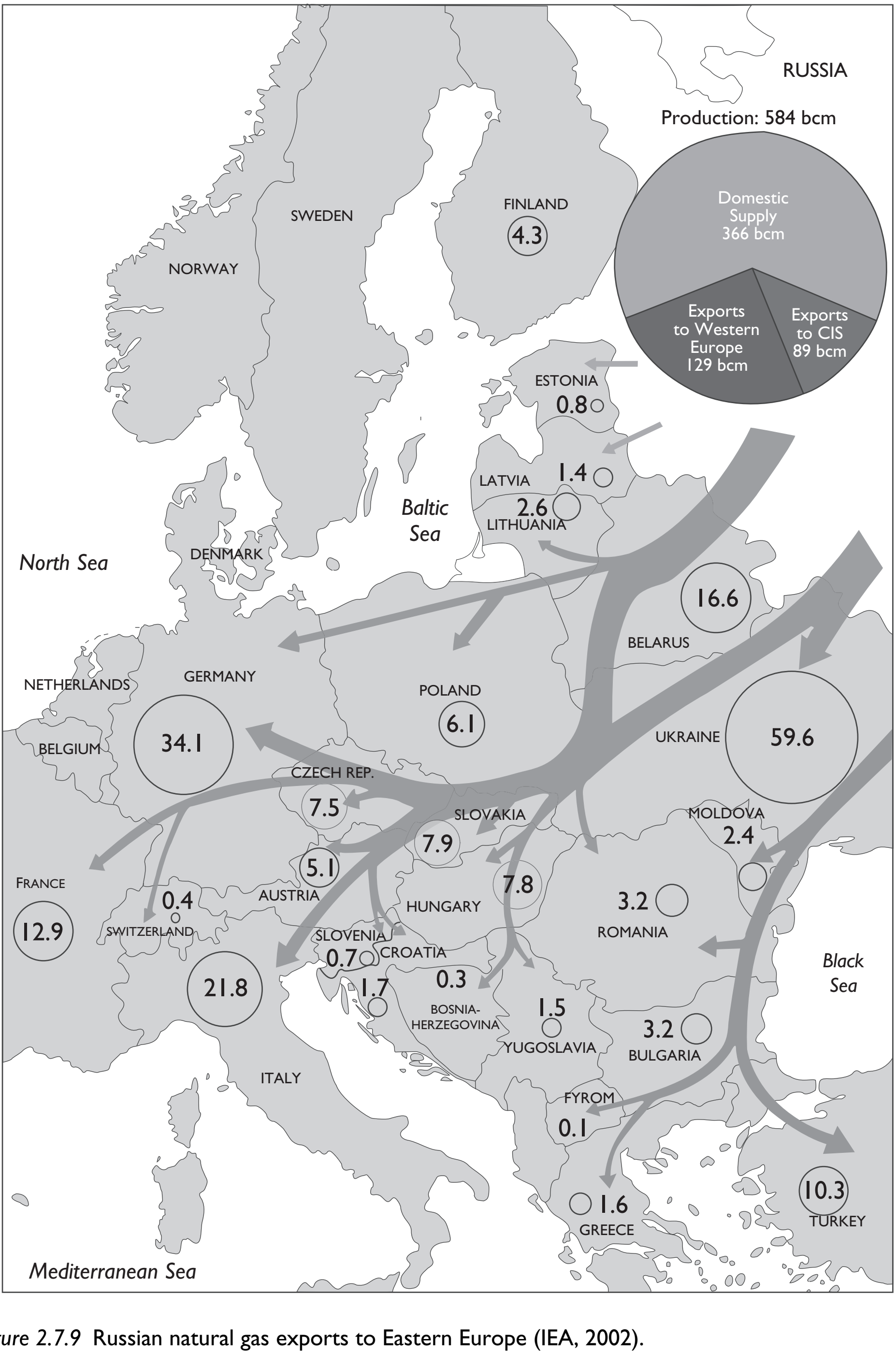


Figure 2.7.9 Russian natural gas exports to Eastern Europe (IEA, 2002).

Table 2.7.5 Russia's natural gas exports to CIS countries (EIA, 2008).

Rank	*Country*	*Imports (bcf/year)*	*Pct of domestic NG consumption*
1	Germany	1110	44%
2	Italy	777	29%
3	Turkey	473	65%
4	France	470	26%
5	Hungary	378	72%
6	Finland	269	100%
7	Slovakia	261	100%
8	Poland	258	60%
9	Czech Republic	240	82%
10	Austria	201	63%
11	Bulgaria	184	94%
12	Romania	177	24%
13	Fmr Yugoslavia	74	–
14	Greece	74	92%
15	Switzerland	18	17%

** Does not include exports through Ukraine and Belarus.

Source: EIA, BP (2005), CIS and E. European Energy Databook, 2005.

Table 2.7.6 Russia's electricity generation by fuel type (IEA, 2005).

	1990	*1993*	*1995*	*1997*	*1999*	*2000*	*2001*	*2002*	*2003*
Total	1082	956	860	833	845	876	890	889	916
Natural Gas	512	430	354	357	359	370	377	385	402
Coal	157	149	161	157	161	176	169	170	174
Hydro	166	173	175	157	160	164	174	162	157
Nuclear	118	119	100	108	122	131	137	142	149
Petroleum Products	129	83	68	52	41	33	30	27	31
Renewables	0	2	2	2	2	3	3	3	3

2.7.4 End-use sectors and carbon dioxide emissions

2.7.4.1 End-use sectors

Russia is the world's fourth largest generator of electricity, behind the United States, China and Japan. Russia's power sector includes over 440 thermal and hydropower plants (approximately 77 of which are coal-fired) plus 31 nuclear reactors (Fig. 2.7.10). A few generators in the far-eastern part of the country are not connected to the power grid. The system has a total electric generation capacity of 205.6 gigawatts (GW), with an output of approximately 850.6 billion kilowatt-hours (BkWh). Since the collapse of the Soviet Union, electricity generation showed both a dramatic decline, (down 18% between 1992 and 1999), followed by a gradual recovery (up 8% between 1999 and 2004). Similar to patterns in oil, natural gas, and coal, the Soviet Union's collapse also stunted electricity generation. Economic recovery contributed to

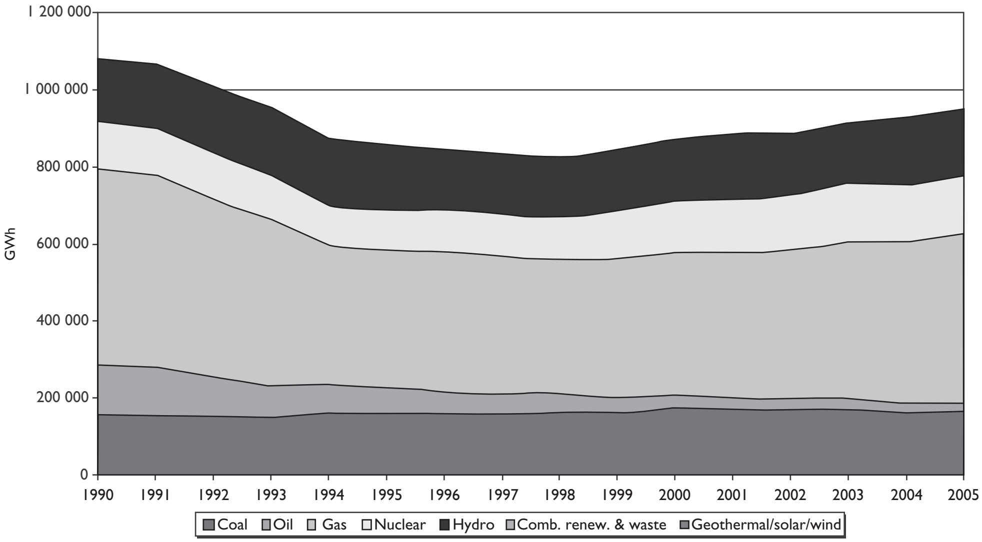


Figure 2.7.10 Annual electricity generation (1990–2005) in Russia (IEA, 2006).

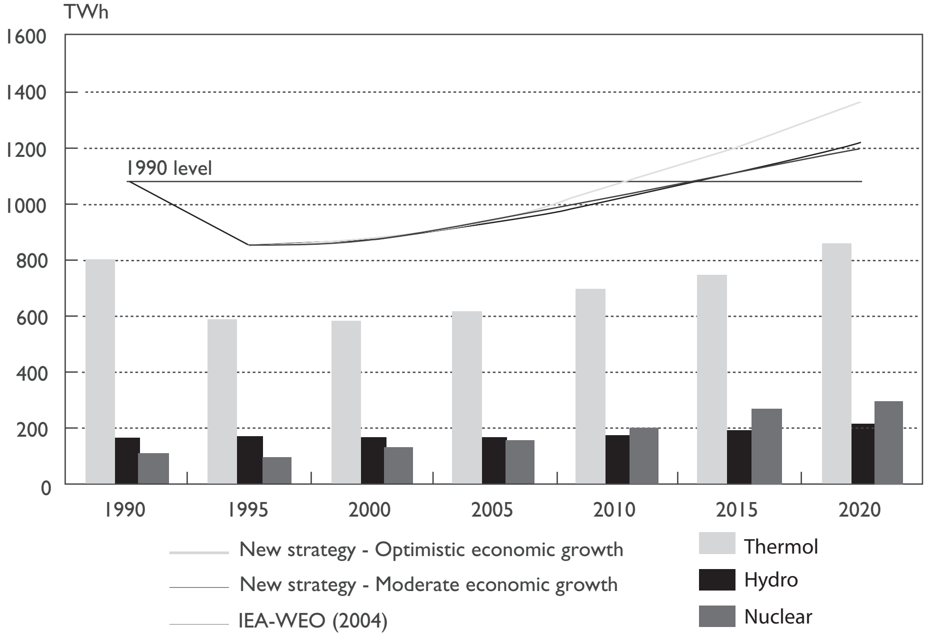


Figure 2.7.11 Russian energy strategy up to 2020 (IEA, 2005).

an increase in total electricity consumption from 715 BkWh in 1998, to roughly 812 BkWh in 2003, and to an increase, to roughly 980 billion kWh in 2007 (Fig. 2.7.11). Thermal power (oil, natural gas, and coal-fired) accounts for roughly 63 percent of Russia's electricity generation, followed by hydropower (21%) and nuclear (16%). The power plants produced 913 billion kWh in 2007, an increase of 2.2% over 2006. Under a favorable economic-growth scenario, the production of electricity is expected reach 1990 levels by 2010.

Due to the shrinking of the national economy in the 1990s, generation fell from 1,082 TWh in 1990 to 827 TWh in 1998. Output increased by more than 2% in 1999, however, to reach 846 TWh. Under a favorable economic-growth scenario, expected electricity production will reach 1990 levels by 2010. In this new context of strong growth and increased electricity demand, the ability to attract the necessary investments is critical. Furthermore the Russian Energy Strategy places particular emphasis on coal and nuclear to redress what is seen as an over-dependence on natural gas. This raises many questions, including the environmental issues due to increased emissions from coal use and the issue of nuclear safety. Russia is a net exporter of electricity to both CIS countries and the "far abroad". In 1999, exports reached 22.5 TWh, accounting for 2.7% of Russian generation. From 1993 to 1998, net exports averaged 18–20 TWh per year, with two-thirds directed to CIS countries. In 1999, exports to Ukraine and Kazakhstan, two of Russia's largest CIS customers, were reduced significantly due to non-payment. Electricity exports to the "far abroad" have been maintained and in some cases increased.

It is hard to separate the electricity and heat sectors in Russia. About 30% of electricity generation comes from co-generation. Electricity is often produced essentially as a by-product of heat, and its sales help cover losses incurred in heat production. District-heating systems in Russia provide heat and hot water to most of the urban population as well as to industry. Heat accounted for 33.2% of Russia's final energy consumption in 1999 and stood at 5,706 PJ (136 Mtoe), down 39% from 1990. The residential sector is the largest heat consumer, with a 48% share in 1999. Industry has 37%. The largest decrease in consumption occurred in industry (minus 49% between 1993 and 1999). The largest industrial consumers in 1999 were chemicals and petrochemicals, machinery and iron and steel. Residential heat consumption decreased 23% over the same period, while consumption in the agriculture sector fell by 38%. Heat generation decreased more than one-third between 1990 and 1999, from 9,467 PJ to 6,333 PJ (151 Mtoe). Natural gas, the most important fuel, accounted for 66% of the total in 1999. Coal accounted for 22%. Input fuels for heat-only plants in 1999 amounted to 91.8 Mtoe, or some 15% of total primary energy supply shows heat generation by fuel.

2.7.4.2 Carbon dioxide emissions

After years of neglect under the Soviet Union, the environment has become a significant issue in Russia today. Soviet policies that encouraged rapid industrialization and development left a legacy of air pollution and nuclear waste with which Russia now is struggling to contend. The country's energy and carbon intensities remain high and have only decreased marginally since the Soviet Union collapsed (Fig. 2.7.12). In addition, despite the objections of nascent environmental groups, the post-Soviet

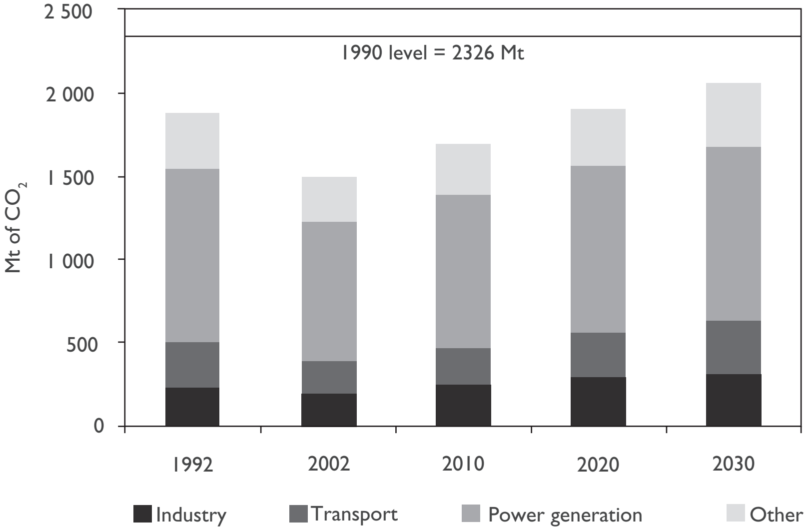


Figure 2.7.12 Carbon dioxide emissions in Russia (IEA, 2004).

Russian government has passed legislation to facilitate the permanent storage of other countries' nuclear waste on Russian territory. Although environmental awareness in Russia is rising, the cost of remedying the country's environmental hot spots is high, and the Russian Ministry of Natural Resources has a limited budget. As a result, cleanup has been slow. In November 2004, Russia ratified the Kyoto Protocol on climate change. The Protocol's targets become legally binding commitments for ratifying countries. Since the fall of the Soviet Union, Russia's GHG emissions have fallen by about a third. Consequently, Russia should not have difficulty meeting its Kyoto target and could earn billions of dollars by selling back the difference between its emissions targets (set in 1990) and its actual emissions. Russian energy sector produces up to 91% of man-made greenhouse gas emissions, about half of all harmful emissions into the air and 30% of all harmful discharges into water. Although such emissions declined in absolute terms over the 1990s, they did not fall as fast as GDP, despite air-management efforts and fuel switching to natural gas, which came to account for half of TPES. At the same time, the threat of increased emissions in future grew with the increased relative importance of heavy and energy-intensive industries, ageing capital stock, lack of investment and systemic inefficiencies in energy consumption. Inefficiencies stemmed from low energy prices, a lack of metering and controls, defects in markets and market discipline and industry's continuing orientation to meeting production goals.

Electricity sector alone contributed 26.8% of harmful emissions in 1999. Upstream oil emissions are the next most harmful within the energy sector, with 9%. All other parts of the energy sector contribute less than 5% of emissions. Total emissions of classic pollutants and CO_2 remain among the highest in the world. Emissions of SO_x and CO_2 per unit of GDP are much higher than OECD averages. Emissions of conventional air pollutants from the energy sector decreased significantly in 1993–1999, due mainly to the economic downturn. However, in some cases, emissions of SO_x, NO_x, particulates, CO, and VOCs decreased less than the decrease in production in each sector over the 1993 to 1999 period. In some cases emissions even increased. Thus, production decline and air-management efforts were more than offset by countervailing factors, including ageing capital stock, lack of investment and systemic inefficiencies in energy consumption. The inefficiencies stem, for example, from low energy prices, a lack of metering and controls, deficiencies in markets and market discipline and industry's continuing orientation to meeting production goals, as opposed to demand-side management.

Although overall oil-sector emissions of pollutants into the air decreased about 29% from 1993 to 1999, the drop came mainly from lower methane and volatile organic-compound emissions. Emissions of SO_x, CO, NO_x and particulates actually *rose* by 46%, 2%, 39% and 64%, respectively. In 1999 CO accounted for 47% of total pollutant emissions from the oil sector, methane 34% and particulates 5%. Despite the doubling of filtering-device capacity in the oil sector in 1999, the wide dispersion of emission sources limited capture. Emissions into the atmosphere increased slightly. The main emissions from the natural-gas sector are methane – a greenhouse gas – CO, SO_x and NO_x. Much progress has been made in reducing emissions of NOx, which fell by almost 60% from 1993 to 1999 thanks to the modernization of combustion chambers and replacement of gas compressor units at compressor stations.

2.7.5 Future scenario

The Energy Information Administration of the U.S. Department of Energy, in its International Energy Outlook-2008 report (EIA, 2008), has projected (Reference Case) future (from year 2005 to year 2030) energy-related requirements and by products for Russia. These are – an increase in total primary energy consumption from 30.3 to 39.9 Quadrillion Btu, an increase in oil consumption from 2.8 to 3.5 MBOE/day (million barrels of oil equivalent), an increase in gas consumption from 16.2 to 20.5 TCF (trillion cubic feet), and an increase in carbon dioxide emissions from 1,696 to 2,117 MMT (million metric tons). The contributions of oil and gas to the year 2030 emissions are 482 and 1,111 MMT, respectively.

Russia's proven natural gas reserves amount to 47 trillion cubic meters, 26% of the world's total. The bulk of Russian gas production comes from three super-giant fields which are now in decline at a rate of 20 bcm/year. Gazprom is facing a steep rise in production costs as it must develop new fields in deeper strata and/or in the Arctic and other difficult-to-develop regions to compensate for the depletion at current fields, let alone to increase production in line with its production targets. The final Energy Strategy approved by the government in August 2003 set Russian gas production needs at between 635–665 bcm in 2010 increasing to 680–730 bcm in 2020. Russia is the world's largest gas producer and exporter. Its role in the emerging global gas market will only gain in importance, as growth is projected both in Russian domestic demand and in international requirements. As the country's key producing fields decline, Gazprom's ability to increase gas production is critical to international energy security. The IEA estimates that at least 30 billion cubic meters – a fifth of the country's exports to European OECD countries – could be saved annually by the introduction of more advanced, available technology and the implementation of energy efficiency. Such investments would be all the more attractive as they would also generate reductions equivalent to 150 million tonnes of CO_2 equivalent. Declining onshore reserves will force resource-rich nations to develop undersea oil and gas hydrocarbons. Roughly 40 percent of global oil and gas will be produced offshore by 2015. The dynamics of the global energy industry explain why Russia's recent polar expedition made international headlines. Moscow's objective was to assert its claim to the vast natural resources of the Arctic Ocean. By 2030–2040 global warming will melt enough of the polar ice cap to make the extraction and transportation of undersea oil and gas possible. Most of the Arctic thaw is taking place in Russia's territorial waters and the Russian Northern Sea Route will probably be open to commercial shipping in 2025–2030.

The entire Russian continental shelf covers 6.2 million square kilometers. Russia's extractable offshore hydrocarbon resources are approximately 100 billion tonnes, 80% of which are located in the Arctic (OIES, 2007). The key problem with estimating the true potential of Russian offshore hydrocarbons is the fact that geological data, on most features, covers only about 9–12 percent of the territory. The only well studied offshore area is the western part of the Arctic, which accounts for 75 percent of all discovered Russian offshore hydrocarbon resources. The Russian Ministry of Natural Resources states that the Russian part of the Arctic contains around 80 billion tonnes of hydrocarbon deposits or 586 billion boe. If Moscow is successful in its bid for more Artic territories, its hydrocarbon share could increase by at least 10 billion tonnes (73.3 boe) or two-thirds of the global annual energy consumption. Thus far, significant oil and gas reserves have been discovered in the Barents, Pechora and Kara Seas and in the Timan–Pechora basin. The Barents Sea includes Shtokman gas and condensate field (3.2 trillion cubic meters of gas and 31 million tonnes of gas condensate) and Prirazlomnoye oil field (about 610 billion barrels of oil). Russia's state-owned gas company, Gazprom, controls both fields.

The Kara Sea basins also possess a substantial hydrocarbon potential. They include the massive Russanov and Leningrad gas and condensate fields, each of which may contain more hydrocarbons than the giant Shtokman field. In the coming decades, oil and gas production from these areas is expected to grow as production declines in traditional Russian hydrocarbon regions, such as the Volga and Urals. Altogether, the western part of the Artic contains 18.4 percent of Russia's oil reserves and 7.6 percent of its gas. Total regional reserves of crude oil, gas-condensate and natural gas are estimated at 53.3 billion barrels of oil equivalent. Despite the region's great promise, the Timan–Pechora basin, which includes the Nenets AO and parts of the Archangelsk Region and the Komi Republic, is the only part of Barents Russia currently producing oil and gas. The East Siberia and Laptev Seas include several basins, some of which are offshore.

At present, Russia's offshore operations only add up to 0.5 percent of the total domestic oil production. By 2020, Russia's strategy on continental shelf development seeks to increase the offshore share in domestic oil and gas output to 20 percent. The Arctic will play a key role in this process. The main question here is whether Russia is capable of active development of the Arctic with its severe polar climate and vulnerable habitats in the foreseeable future. In this respect, the key obstacles include the lack of relevant experience and technologies, virtual absence of all essential industrial equipment and vital infrastructure in the Arctic regions, a problematic regulatory regime and the fiscal environment.

The lack of geological data in the Russian section of the Arctic is a serious problem. Most of the current hydrocarbon resources in the Russian part of the Artic, such as the Shtokman and Prirazlomnoye fields, were discovered by Soviet geologists in the late 1970s and the 1980s. After the collapse of the USSR in 1991, the Russian federal government ceased state funding of geological expeditions. As a result, in early 2007, the Russian part of the Arctic contained only 58 wells, whereas the Norwegians had already drilled about 1,500 wells in their section.

In Russia, energy consumption for passenger transportation increases at an average rate of 0.6 percent per year from 2005 to 2030 in the reference case, even as the Russian population declines by an average of 0.6 percent per year (for a total population reduction of 20 million). Russia's automobile market has been particularly strong in the past several years, with 1.5 million vehicles sold in 2005 and expectations by some analysts that sales may expand by 7.0 percent per year until 2010. Thus, passenger energy use per capita is projected to increase by an average of 1.2 percent per year. Strong economic growth, fueled by sustained high prices for Russia's exports of oil and natural gas, increases the demand for personal motorization.

Russia has 41 oil refineries with a total crude oil processing capacity of 5.4 million bbl/d, but many of the refineries are inefficient, aging, and in need of modernization. Based on EIA analysis, Gazprom's production from its largest four fields is expected to decline by around 1,800 Bcf in the next four years. Gazprom's targeted production for 2011 is an increase of around 1,000 Bcf from 2007 levels. The average level of depletion at Russia's five largest producing fields (not including Zapolyarnoye) was almost 50 percent in 2006, weighted by production.

For Russia, the two fastest-growing energy sources for electric power in the mid-term projection are natural gas and nuclear power. Both are expected to grow by an average of 3.2 percent per year from 2005 to 2030. With its extensive natural gas reserves, Russia currently generates nearly 40 percent of its electricity from natural gas, and the share increases to 46 percent in 2030. Russia is the world's fourth largest generator of electricity, after the United States, China and Japan. In 2003, it produced 916 TWh, an 11% increase over 1998. Thermal generation accounts for 66% of total production, and two-thirds of that amount comes from natural gas. Russia is pursuing a strategy of very high economic growth, with an objective of doubling its gross domestic product in ten years. Efficient and reliable electricity markets will be critical to the success of this policy. The Russian government has embarked on a highly ambitious program of electricity reform. Russia has huge investment needs. The International Energy Agency's *World Energy Outlook 2003* estimated the electricity sector's total investment requirement from 2003 to 2030 at about $380 billion. That figure amounts to 1.9% of the country's GDP over the period. But the bulk of this investment will not be needed till after 2010.

Among the non-OECD countries, Russia has the highest projected increase in carbon dioxide emissions per capita in the *IEO2008* reference case, from 12 metric tons per person in 2005 to 17 metric tons in 2030 (Figure 84 and Table 14). A projected decline in Russia's population, In 2004 Russia emitted an estimated 298 million tonnes of CO_2 equivalent ($MtCO_2e$) of GHG from its natural gas transmission and distribution systems, Russia's rather inefficient gas transmission system is a large emitter of GHG.

In comparison with foreign gas systems, its high energy intensity is due mainly to the large number of low efficiency compressor units along Gazprom's transmission system and to the ageing of its facilities.

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SECTION-III
Energy from the Atom

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PREAMBLE

The world is experiencing a nuclear renaissance. Several factors are driving the "resurgence" of nuclear power (Ewing, 2006).

i It is a proven technology – nuclear power currently accounts for about 16% of the electricity production in the world,
ii Energy release from nuclear reaction per unit mass is about a million times more than chemical combustion,
iii The volume of waste produced is small (typically, 20 t per reactor per year), and is generally contained (as against wastes from coal use which get widely dispersed),
iv The radioactivity and radio toxicity of the Spent Nuclear Fuel (SNF) drop steeply in thousand years, after removal from the reactor,
v New reactor designs and advanced fuel cycles permit the virtual elimination of "waste" radio nuclides like Np, and permit the generation of new fissile material (^{239}Pu from ^{238}U, or ^{233}U from ^{232}Th),
vi Most importantly, nuclear power plants do not emit greenhouse gases.

A MIT study (Ansolabehere et al., 2003) projects that the nuclear power will grow from 350 GWe today to 1500 GWe in 50 years. This would need about 10 Mt of uranium. The uranium resources that are known to exist at a conservative estimate (~23 Mt) will suffice at least up to 2100, if not longer.

The present level of carbon displacement by nuclear power is about 0.5 Gt C/yr. A ten-fold increase of nuclear power would require the building of additional 3500 GWe of nuclear power, which would generate about 100,000 t of spent nuclear fuel containing about 700 t of plutonium. A more modest three-fold increase of nuclear power would require the creation of about 2 GWe capacity per month, and assuming open fuel cycle, would require repository capacity of about 20,000 t equivalent of spent nuclear fuel every year.

Though the case for nuclear power is compelling, three issues of public concern are impeding its growth: (i) safety of the nuclear power plants, (ii) disposal of the nuclear wastes, and (iii) possibility of diverting nuclear materials for the production of nuclear weapons. This Section hence focuses on new technologies of nuclear waste disposal, design of fail-safe reactors in which meltdown is not possible, and nuclear fuel cycles which generate less waste. The nuclear weapons issue is the toughest of all because of its high military-political significance (it needs only six kgs. of ^{239}Pu to make a nuclear weapon). New kinds of "symbiotic" fuel cycles are being developed, which are characterized by lower inventory of mixtures of radionuclides that cannot be easily made into nuclear weapons. These technologies coupled with strict controls, may one day make it possible to spread the nuclear power, without worrying about proliferation.

This Section draws extensively from the earlier work of the author (*Principles of Nuclear Geology*, 1985), *Elements*, Dec. 2006, and IEA's *Energy Technology Perspectives, 2008.*

3.1 NUCLEAR POWER

3.1.1 Radiation units

Table 1.1 Gives the units of radioactivity and dose.

Unit	*Symbol*	*Conversion factors*
Becquerel (SI)*	Bq	1 disintegration = 2.7×10^{-11} Ci
Curie	Ci	3.7×10^{10} disintegrations/s
Gray (SI) (unit of *absorbed* dose)	GY	1 J/kg = 100 rads
Rad	rad	0.01 Gy = 100 erg/g
Sievert (SI) (unit of *equivalent* dose)**	Sv	1 J/kg = 100 rem
Rem	rem	0.01 Sv

Source: Ewing, 2006.

* SI (Systeme International) units.

** Sievert (Sv) takes into account the type and effect of the radiation. Equivalent dose (Sv) is obtained by multiplying absorbed dose (Gray) with Q, a quality factor (e.g. Q = 1 for X-rays and 20 for alpha particles).

Radiation doses (U.S. Regulations)

Indoor radon	4 pCi/l (=0.1 Bq/l)
High-level nuclear waste standard	15 mrem/y (=0.15 mSv/y)
Emission standards for air pollutants	10 mrem/y (=0.1 mSv/y)
Water protection standard	4 mrem/y (=0.04 mSv/y)

Average amount of ionizing radiation to which a typical person is exposed: 3 to 3.5 mSv/y (over half of which is from radon exposure).

P = pico = 10^{-12}; m = milli = 10^{-3}.

3.1.2 Fissile and fertile radioactive isotopes

Radioactive nuclides are those nuclides which are inherently unstable. They decay spontaneously into other nuclides (stable or unstable) at a fixed, measurable rate, accompanied by the emission of radiations. There are three naturally occurring radioactive series.

$$^{232}\mathrm{Th} \rightarrow {}^{208}\mathrm{Pb} + 6\alpha + 4\beta + \mathrm{Q}$$

where Q = 39.8 MeV/atom

$$^{235}\mathrm{U} \rightarrow {}^{207}\mathrm{Pb} + 7\alpha + 4\beta + \mathrm{Q}$$

where Q = 45.2 Mev/atom

$$^{238}\mathrm{U} \rightarrow {}^{206}\mathrm{Pb} = 8\alpha + 6\beta + \mathrm{Q}$$

where Q = 47.4 MeV atom.

The Neptunium series are artificially produced. The half-lives of the members of the series are so short-lived that they might have become "extinct" during the early history of the earth. They are hence not recognizable in the crustal rocks. Unlike the other naturally radioactive series which end up in Pb, the Neptunium series ends up in Bi.

$$^{237}Np \rightarrow {}^{209}Bi + 7\alpha + 4\beta + Q$$

Only fissile isotopes can be used directly in nuclear fission for generating power. Fertile isotopes have to be rendered fissile first, before being used to produce nuclear fission. Uranium has two isotopes – fissile isotope ^{235}U with an abundance of about 0.7%, and fertile isotope ^{238}U with an abundance of about 99.3%. Neutron absorption in ^{238}U produces the fissile plutonium isotope, ^{239}Pu. On the other hand, thorium has no fissile isotope, but consists entirely of fertile isotope ^{232}Th which has to be converted to fissile ^{233}U through neutron absorption before being used for nuclear fission. ^{233}U produces the most neutrons per neutron absorption at thermal energies (slow neutrons) and is hence superior to both ^{235}U and ^{239}Pu as nuclear fuel in the common light water thermal reactors.

Enriched uranium fuel, which is used in the reactors, is produced by enriching the ^{235}U content to 4–5%. ^{233}U does not occur in nature – it has to be "bred" (hence the term, breeder reactors). Enriched uranium (typically, 20% ^{235}U) or ^{239}Pu is needed for the start-up of such reactors. When thorium is substituted for natural uranium in a breeder reactor, as much (or more) ^{233}U is produced by neutron absorption in thorium, as is consumed in the reactor operation. Also, when once the reactor is started, no further enriched uranium is needed.

Power reactors: The fissioning of one kg of ^{235}U yields 22.66×10^6 kWh of energy, equivalent to 2750 t of bituminous coal. The fuel value of one ton of uranium is 6.8×10^{13} BTU. The very high fuel value of uranium has profound implication for siting the nuclear power plants. While coal-fired thermal power stations have to be established at pithead in order to save on transportation costs, and hydroelectric power stations have to be set up at dam site, a nuclear power station is not subject to such constraints (a 1000 MWe power station would need annually about 3.1 million tonnes of hard coal, but only about 24 tonnes of enriched uranium).

3.1.3 Uranium resources

3.1.3.1 Important uranium minerals

Table 3.1.1 Principal uranium minerals.

Mineral	*Chemical composition*	*Mode of occurrence*
Uraninite	UO_2; U = 46.5–88.2%	Vein deposits and pegmatites
Pitchblende	UO_2 (colloform)	High temperature hydrothermal veins (with haematite); Low temperature hydrothermal veins with sulphides of Co-Ni-Bi-Ag-As; Disseminations in metamorphic rocks and replacement lodes in sandstones and conglomerates. Pyrochlore
Pyrochlore* (and microlite)	$(Na, Ca)_2 (Nb, Ta)_2 O_6 (O, OH, F)$; UO_2 upto 11.5%	Alkali syenites, pyrometasomatic marbles, placers
Fergusonite* (and formanite)	$(Y, Er, U, Th) (Nb, Ta, Ti) O_4$	Granite pegmatites; less commonly in placers; association with allanite, zircon, samarskite, and euxenite

(*Continued*)

Table 3.1.1 (*Continued*)

Samarskite* (and yttrotantalite)	(Y, Ce, U, Th) $(Nb,Ta)_2O_6$; UO_2 upto 8.16%	Granite pegmatites in association with columbite, zircon, monazite; occasionally in placers.
Euxenite* (and polycrase)	(Y, Ce, U, Th) $(Ti, Nb, Ta)_2O_6$; UO_2 upto 14%	Granite pegmatites in association with columbite, zircon, monazite; occasionally in placers.
Betafite	(U, Ca) $(Nb,Ta,Ti)_3O_9 \cdot n \cdot H_2O(?)$	Granite pegmatites; occasionally in placers.
Brannerite	$(U, Ca, Fe^{2+}, Y, Th)_3$ $(Ti, Si)_5 O_{16}$ (?) U-27.9 to 43.6%; Th-0.26 to 4.4%	Metamorphosed quartz pebble conglomerate; veins; occasionally in placers (along with gold).
Thucholite	Uraniferous hydrocarbon complex. Ash may contain from 1 to 70% of U_3O_8.	Pegmatites, hydrothermal veins and lodes; asphaltites.
Gummite	Mixture of hydrous oxides and silicates	Pegmatites and vein deposits – as alteration product of uraninite and pitchblende, and uranothorite.
Carnotite	$K_2(UO_2)_2(VO_4)_2 \cdot 1\text{–}3\ H_2O$; UO_3: 63–65%	Most abundant secondary uranium mineral. Occurs in oxidized zones of U-V ores of the Colorado Plateau type. Associated with tyuyamunite.
Tyuyamunite (and metatyuyamunite)	$Ca\ (UO_2)_2(VO_2)_2 \cdot 7$ to $10.5\ H_2O$; UO_3: 57–58%	Oxidised zones of the Colorado Plateau-type U-V ores.
Autunite (and metaautunite)	$Ca\ (UO_2)_2(PO_4)_2 \cdot 10$ to $12\ H_2O$; UO_3: 57–58%	Wide-spread secondary mineral; forms under oxidizing conditions, in (i) uraniferous phosphatic pegmatites, (ii) Pitchblende veins, and (iii) Oxidised Colorado Plateau type deposits.
Torbernite (and metatorbernite)	$Cu\ (UO_2)_2(PO_4)_2 \cdot 8$ to $12\ H_2O$; UO_3: 57–58%	Widespread oxidation product of uraniferous pegmatites, U-Cu veins, especially gossans of such veins.
Uranophane	$Ca\ (UO_2)_2(SiO_3)_2 \cdot 7$ to $10.5\ H_2O$; UO_3: 57–58%	Most abundant uranium silicate. Occurs in oxidized parts of pegmatites, veins and lodes, and Colorado Plateau type deposits.

Source: Aswathanarayana, 1985, pp. 74–82.

* Forms solid solution with the mineral shown in parentheses.

3.1.3.2 Geochemistry and geologic setting of uranium deposits

U^{4+} (radius: 1.05 Å) and Th^{4+} (radius: 1.10 Å) go together in the magmatic environment. They get enriched in acid rocks (Th: 12 ppm, U: 3 ppm), relative to the basic rocks (Th: 3 ppm; U: <1 ppm), and their contents are largely in accessory minerals, like allanite, zircon and monazite. Consequently, uranium is preferentially enriched in the continental portion of the earth's crust, and depleted in the oceanic crust. Uranium gets incorporated in the subduction zone magmas, and then rises through the overlying crust. It may later get partitioned in hydrothermal solutions.

In the late-stage granitic magmas and hydrothermal solutions, U^{4+} gets oxidized to highly soluble uranyl ion $(U^{6+}O_2)^{2+}$, while Th^{4+} remains unchanged and immobile. In the exogenous conditions, uranium gets transported in the form of uranyl carbonate $[UO_2(CO_3)]$ and hydroxide $[UO_2(OH)_2]$, uranyl humate, and phosphate complexes, and gets precipitated when reducing conditions (say, due to the presence of H_2S and organic matter) are encountered. This accounts for the close association of uranium ores with organic matter (e.g., sooty pitchblende). Generally, uranium deposits form due to the interaction of uranium-rich fluids with the country rocks. Th-bearing minerals are resistant to weathering, and form placers (e.g. monazite placers). Uraninite does not form placers (except in palaeo-placers associated with quartz-pebble conglomerates which formed when the earth's atmosphere was reducing).

During the Archaean period, from 3800 to 2500 million years ago, there was more radiogenic heat, and the earth's crust was hence more mobile. There was increase in the growth of the continental crust during 3200 to 2600 million years ago, and this was accompanied by the deposition of the first uraniferous quartz-pebble conglomerate (Plant et al., 1999). Large plutons of uraniferous granites (with uranium contents of the order of 600 ppm) were emplaced about 2500 million years ago, and these may be related to the tectonic activity probably related to the assembly of the supercontinent (Crowley et al., 2005).

Bulk of the uranium resources in the world are associated with haematite breccia type (Olympic Dam, Australia), unconformity type (Canada and Australia), Phanerozoic, fluviatile quartzose sandstones and mudstones of continental origin (e.g. Colorado Plateau), and oligomictic, quartz-pebble conglomerate in the Precambrian shield areas (e.g. Blind River, Canada, and Witwatersrand, South Africa).

The highest grade uranium deposits in the world (0.12% to 22.28% uranium) are of Proterozoic age, and occur in Australia and Canada. They are related to the unconformities between the Archaen-early Proterozoic metasedimentary rocks and mid-Proterozoic sandstones. Uranium is associated with pyritic conglomerate and carbonaceous seams which are sometimes gold bearing. Such association demands a reducing environment, irrespective of whether or not the atmosphere is oxygenating. Pretorius (1976) developed the following paradigm for the formation of gold-uranium deposits of South Africa. The Archaean granitoids containing gold and uranium were uplifted, and their erosion products were dumped in a lacustrine basin. The sediments were coarse as a consequence of high gradients and short fluvial transportation. Part of the basin had algal mats. Uplift of the sediments (along a fault) permitted the recycling of sediments. The organic acids produced by the photosynthetic activity of the algae in the lacustrine basins, have been responsible for the deposition of gold and uranium (it has been found that gold can be transported as organic-protected gold colloids). The principal minerals are uraninite and thucholite, and uranium is a byproduct of gold mining. It is economical to extract uranium from the gold tailings, even though the concentration of uranium is low (about 1000 ppm). In the case of the Blind River uranium deposit in the Missisagi pyritic conglomerate, which overlies the pre-Huronian basement, the principal minerals are brannerite, uraninite and thucholite.

The uranium deposits of the Colorado Plateau are of two types: (i) Uranium–vanadium mineralization (carnotite and tyuyamunite) in the Morrison and Entrada formations of Jurassic age: Mineralisation occurs where sandstone facies change to mudstone facies (with attendant marked change in the porosity and permeability) and where the environment is suitable for the precipitation of uranium (grey sandstones with "rolls" containing fossilized tree trunks). These rolls are rich in uranium (0.09–0.43% U), and vanadium (1.5–2% V_2O_5), (ii) Uranium – copper mineralisation (pitchblende, autunite and torbernite) in the Moenkopi, Shinarump and Chinle formations of Triassic age. The conglomerates in the lows of the palaeo-stream channels, are the host rocks for uranium minerals.

Uranium is associated with veins in granites (0.025–0.035% U). Vein deposits of uranium are associated with nickel-cobalt-native silver veins in metasediments and volcanics (e.g. Great Bear Lake, Canada), silica-iron-lead veins in felsic intrusives (e.g. Marysvale, Utah), and iron-titanium veins in grantic intrusives and metasediments (Radium Hill, South Australia). Rhyolites and trachytes, associated with continental extensional settings, contain uranium (0.04–4% U).

Uranium is associated with the marine black shales and phosphorites (e.g. Cambrian Alum shale of Sweden which contain dark bitumen called "kolm" assaying as much as 0.5% U; Cambro-Ordovician Dictyonema shales of Leningrad (0.007–0.025% U). The uranium content in phosphorites is related to organic matter and P_2O_5 content, and is inversely proportional to CO_2 contents. Uraniferous phosphorites have been reported from Morocco (0.010–0.012% U).

Seawater which contains 0.5–3.3 ppb of U constitute a vast source of uranium, but there are formidable technical difficulties. This process may be of interest to countries like Japan which have no uranium resources. Japanese scientists developed a highly selective, inexpensive amidoxime adsorbent, through which the seawater could pass without loss of head. The process could be driven with ocean currents of modest magnitude (1 m/s), without the use of external power. The recovery costs range from \$400–1200/kg (Seko et al., 2003).

The OECD (Organisation of Economic Cooperation and Development) Nuclear Agency in cooperation with the IAEA maintains a document (colloquially known as the Red Book) on the production of uranium in the world. According to the 2007 edition of the Red Book, at the end of 2006, 435 commercial reactors produced 370 GWe of electricity, using 66,500 Ut (tonnes of uranium) (39,603 Ut from primary sources and the remainder from secondary sources). By 2030, the increase in global nuclear power capacity may range from 509 GWe (requiring 93,775 Ut) to 663 GWe (requiring 121,955 Ut). In 2007, the Total Identified Resources (Reasonably assured and Inferred) is 4,456,000 Ut in the <USD 40/kg category, and 5,469,000 Ut in the <USD 130/kg category.

Table 3.1.2 gives the geologic setting of the important producing uranium deposits in the world as listed in the Red Book in the order of their economic importance. Further details about the uranium deposits could be had from OECD Nuclear Energy Agency (2005).

Seven countries (Canada, 29%; Australia, 22%; Kazakhstan, 9%; Russia, 8%; Niger, 8%; Namibia, 8%; Uzbekistan, 5%) account for about 90% of the world production. The cost of uranium was \$27.74/kg in 2004, and \$31.59/kg in 2005. Though

Table 3.1.2 Geologic setting of the important uranium deposits in the world.

	Classification	*Geologic setting*	*Location of important deposits*
1	Unconformity deposits	Continental post-orogenic basins	Athabasca Basin, Canada; McArthur Basin, Australia
2	Sandstone	Continental post-orogenic basins	Colorado Plateau, USA; Moynkum, Kazakhstan; Westmoreland, Australia; Akouta, Niger; Hamr-Straz, Czech Republic
3	Haematite breccia complexes	Acid igneous rocks	Olympic Dam, Australia
4	Quartz pebble conglomerate	Continental post-orogenic basins	Witwatersrand basin, South Africa; Blind River/Elliot Lake, Canada
5	Vein deposits	Continental post-orogenic basins (sedimentary host) Associated with hydrothermal fluids (igneous host) Associated with hydrothermal fluids (metamorphic host)	Schwartzwalder, USA; Dhaba district, Congo Massif Central, France; Iberian Meseta, Spain, Portugal Pribram, Czech Republic
6	Intrusive deposits	Alkaline complexes	Rossing, Namibia; Illimaussaq, Greenland; Palabora, South Africa
7	Volcanic and caldera-related deposits	Felsic volcanics	Streltsovsk caldera, Russia; Dornot deposit, Mongolia; Nopal deposit, Mexico
8	Metasomatite	Igneous	Pervomayskoe, Ukraine; Lagoa Real, Brazil; Valhalla, Australia
9	Surficial deposits	Sedimentary	Yeelirrie, Australia; Langer Heinrich, Namibia
10	Collapse breccia type	Continental – Sedimentary	Arizona strip, Grand Canyon, USA
11	Phosphorite deposits	Marine sedimentary deposits	Uncle Sam, USA; Gantour, Morocco; Al-Abiad, Jordan
12	Miscellaneous	Metamorphic Limestone Uranium-rich coal	Forstau, Austria; Mary Kathleen, Australia Grants, USA Serres basin, Greece; North and South Dakota, USA
13	Rocks with high Uranium content	Pegmatite Black shale	Greenbushes, Australia Chattanooga Shale, USA; Chanziping, China; Gera-Ronneburg, Germany

Source: Macfarlane & Miller, 2007.

the fuel costs of nuclear power ($0.018/kWh) are not much different from those of thermal power ($0.023–0.05/kWh), the capital costs of building a new nuclear plant ($2000/kWe) are much higher than for a modern gas turbine plant, which could be built as cheaply as $500/kWe (source: Macfarlane and Miller, 2007).

3.1.4 Thorium resources

The principal minerals of thorium are listed in Table 3.1.3.

Monazite is the principal ore of thorium. Vein deposits of monazite are known, but they are economically insignificant. The most important resources of monazite are detrital, and are associated with ilmenite-bearing heavy mineral sands, which occur as coastal and inland placers.

India has one of the largest resources of monazite in the world – about 10.1 million tonnes which contain ~0.72 million tonnes of ThO_2 (Dhanaraju, 2005, p. 53; personal communication). They are located in Chhatrapur-Gopalpur in Orissa, Bhavanapadu-Kalingapatnam-Bhimunipatnam in Andhra Pradesh, Manavalakurichi in Tamil Nadu, Chavara in Kerala, and Ratnagiri in Maharashtra.

These are all surface deposits, and can be mined easily with the least environmental degradation. Floating plants with hydraulic dredging or bucket line dredging could be employed for the dislodgement and lifting up of the heavy mineral sands. Heavy minerals, which typically constitute about 5% of the sands, are separated electromagnetically on board the ship, and the rest about 95% is dumped back at the same site. This way, the environmental impact of mining is minimized.

Incidentally, the Corridor Sands deposit of heavy minerals (~17 billion tonnes of heavy mineral sands, with about 5% of the Total Heavy Minerals) in the Limpopo palaeo-delta in the Gaza province of Mozambique, has emerged as probably the largest deposit of monazite in the world (Taylor et al., 2003).

The estimated resources of thorium in the other parts of the world (USD 80/kg Th) are as follows: Australia: 452,000 t; USA: 400,000 t; Turkey: 344,000 t; Venezuela: 300,000 t; Brazil: 221,000 t; Norway: 132,000 t; Egypt: 100,000 t; Russia: 75,000 t; Greenland: 54,000 t; Canada: 44,000 t; South Africa: 18,000 t; Other countries: 33,000 t. (*source: Geoscience Australia 2006 and OECD/NEA Red Book retrospective, 2006*)

The 2005 IAEA-NEA "Red Book" gives a figure of 4.5 million tonnes of thorium reserves, but this data is neither complete globally, nor is it based on systematic exploration.

Table 3.1.3 Principal minerals of thorium.

Mineral	*Chemical composition*	*Mode of occurrence*
Monazite	(Ce, La) PO_4; ThO_2 upto 12%; U_3O_8: 0.1–10%	Accessory in granites and several metamorphic rocks. Present in granite pegmatites. Most common in placers.
Thorite	$ThSiO_4 \cdot$ U upto 10%; ThO_2: 49–75%	Granite pegmatites, Quartz-haematite-baryte veins; fluorite-rich veins; placers.
Thorianite	(Th, U) $O_2 \cdot$ U upto 46.5%; Th: 45.3–87.9%	Metasomatised marbles; stream placers.
Allanite	$(Ca, Ce, Th)_2$ $(Al, Fe, Mn, Mg)_3$ $(SiO_4)_3 \cdot OH \cdot$ Th upto 3.2%; U minor	Widespread accessory mineral in acid and intermediate rocks. Occurs in granites, pegmatites, and pyrometasomatic marbles.

Source: Aswathanarayana, 1985, pp. 74–82.

3.1.5 Three-stage development of nuclear power in India

Under the visionary leadership of Homi Bhabha, the father of atomic energy development, India has embarked on a three-stage development of nuclear power to make use of its extensive thorium resources and limited uranium resources (Jain, this volume).

Stage 1: Pressurised Heavy Water Reactors (PHWRs, elsewhere known as CANDUs) which are fueled by natural uranium. In the fission process, fissile ^{239}Pu is formed by the neutron bombardment of ^{238}U. India uses the closed nuclear fuel cycle. The spent nuclear fuel is kept in interim storage for about five years to remove decay heat before reprocessing to recover ^{238}U and ^{239}Pu and remove other fission products.

Stage 2: Fast Breeder Reactors (FBRs) use the plutonium-based fuel from PHWRs, to breed ^{233}U from ^{232}Th. The blanket around the core will have uranium as well as thorium, so that further plutonium (ideally high-fissile ^{239}Pu) is produced as well as ^{233}U. Thus the FBRs produce both energy and fuel, and are hence termed breeders. FBRs produce more fuel than they consume. Over a period of time, Plutonium inventory can be built by feeding Uranium^{238}. In the second stage, when once sufficient inventory of ^{239}Pu is built up, ^{232}Th which is introduced as a blanket material will be converted to ^{233}U.

Stage 3: Advanced Thorium Reactors which burn ^{233}U as fuel. ^{232}Th is directly used as fuel in this stage along with plutonium, getting about 75% of their power from thorium.

It should be emphasized that without first producing plutonium in adequate quantities through the operation of first generation reactors using natural or enriched uranium, it is not possible to initiate any significant programme of throrium utilization.

As the three-stage programme is sequential with lead time involved at each stage, utilization of thorium directly as a fuel will take time. Hence India is developing the innovative Advanced Heavy Water Reactor (AHWR) and Accelerator Driven Systems (ADS), which produce little waste, as the actinides produced in the fission process will also be 'burnt'. The AHWR is a bridge between the first and third stage systems.

Enriched uranium fuel, which is used in the reactors, is produced by enriching the ^{235}U content to 4–5%. ^{233}U does not occur in nature – it has to be "bred" (hence the term, breeder reactors). Enriched uranium (typically, 20% ^{235}U) or ^{239}Pu is needed for the start-up of such reactors. When thorium is substituted for natural uranium in a breeder reactor, as much (or more) ^{233}U is produced by neutron absorption in thorium, as is consumed in the reactor operation. Also, when once the reactor is started, no further enriched uranium is needed.

The thorium cycle has a number of benefits: (i) The spent fuel has lower toxicity, due to reduced production of long-lived isotopes of elements such as neptunium, americium, curium as well as plutonium, (ii) The mixed thorium cycle produces less weapons-grade material than the standard uranium cycle, and thus has a greater degree of weapons proliferation resistance, (iii) ThO_2 has better thermophysical properties and chemical stability relative to UO_2, which results in better in-pile performance and more stable waste form in the case of the thorium fuel, and (iv) Superior plutonium incineration in (Th, Pu) O_2, relative to (U, Pu) O_2.

The single most important benefit of nuclear power is that no carbon dioxide (a green house gas) is emitted. This is a critically important consideration in the context of global warming due to CO_2. The substitution of nuclear electricity for coal would reduce the CO_2 emissions by 92 Gt (giga tonnes or 10^9 tonnes) over 50 years, and would allow the CO_2 emissions to be stabilized at their current level of 25.6 Gt CO_2/yr (Pacala and Socolow, 2004).

A Light-Water Reactor (LWR) producing 900 MWe requires 20 t of metallic uranium per year. Mining of 17,000 t of 1% U ore is required to produce 20 t of metallic uranium (~22.7 t of UO_2). About 160 t of U from UF_6 feed is enriched to about 4% ^{235}U – this would need the expenditure of 100,000 SWU (Separative Work Units in terms of kg/SWU) which is the amount of work to be done to produce a specified level of enrichment).

While coal-fired thermal power stations have to be established at pithead in order to save on transportation costs, and hydroelectric power stations have to be set up at dam site, a nuclear power station is not subject to such constraints (a 1000 MWe power station would need annually about 3.1 million tonnes of hard coal, but only about 24 tonnes of uranium). In the context of agitations for using land for non-agricultural purposes, this is an important consideration as the atomic power plants can be established in rocky, barren land away from habitations. Also, much progress has been made in regard to two issues of concern to the general public, namely, reactor safety and disposal of radioactive wastes. Inherently safe reactors (High Temperature Gas Reactors) in which the dreaded meltdown is not possible, are being designed. About 25–30 t of spent fuel is generated per GWe. Deep geological repositories of massive, hard rock in aseismic, arid, uninhabited areas are the favoured sites for nuclear waste disposal, and such sites do exist in India.

3.2 DISPOSAL OF URANIUM MILL TAILINGS[1]

3.2.1 Introduction

Low-level wastes are produced during the mining and extraction of uranium ore, and milling for the physical and chemical extraction of uranium from the ore. Mining and mill tailings constitute the largest quantities of wastes, and contain all the naturally occurring radioactive elements contained in the uranium ore.

In 2004, there was production of about 40,263 t of uranium worldwide. The mining of uranium in about 4000 mines, generated 938 M m^3 of mill tailings worldwide. As the market price of uranium (presently USD 50–60/kg, after peaking at USD 135/kg) has doubled since 2002, mining of uranium and the production of mill tailings are increasing rapidly. Though the quantity of uranium tailings is a small fraction of about 18 billion m^3 per year of mine tailings in the mining industry as a whole, the environmental consequences of uranium mill tailings pro rata are more serious because of their radioactivity and the geochemical attributes of the tailings. The radioactivity of the tailings may vary from 1 Bq/g to 100 Bq/g, depending upon the uranium content

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[1] This chapter draws extensively from Abdelouas (2006).

of the ore. The radiation risks of the tailings arise from gamma radiation, radon gas and its radioactive progeny, due to the decay of radium. Radon and its progeny could cause cancer. The usual practice is to impound the tailings near the mine or the mill. Windblown dust from the tailings is radioactive and its inhalation could cause cancer. Sulphide minerals, such as pyrites (FeS_2) are often present in the tailings, to the extent of a few to tens of wt.%. Acid Mine Drainage (AMD) gets generated due to the oxidative dissolution of the sulphide minerals. Both purely chemical reactions as well as microbially-catalysed reactions are involved. Under oxidizing conditions, and in the presence of catalytic bacteria, such *Thiobacillus ferroxidans*, sulphides are oxidized into sulphuric acid. Surface water and groundwater seepages associated with waste piles, tend to be highly acidic and corrosive.

Uranium is mined by opencast, underground and in situ leaching methods, depending upon the grade, size, geologic setting and location of the orebody. In 2004, uranium was produced by underground mining (40%), opencast mining (27%), and in situ leaching (21%) and as a byproduct (12%) (see Section 1 for details about the methods of opencast and underground mining). Opencast mining is generally limited to a depth of about 300 m. The wastes from the opencast mining and underground mining generally consist of soil and waste rock overburden, rock excavated from underground and drill cuttings. The wastes may contain trace amounts of uranium and radioactive decay products. In situ leach mining may not have any surface manifestation, but may lead to groundwater contamination. Secular equilibrium may have been attained in the uranium deposit between ^{238}U and ^{235}U and their decay products, but geochemical processes involving (say) the movement of uranyl ion, may disturb the secular equilibrium.

After uranium is extracted from the ore, the mill tailings are likely to contain virtually all the nuclides in the uranium decay series, particularly those of ^{238}U. It is necessary to understand the mineralogy and geochemistry of the tailings, as they have a bearing on the environmental consequences of milling wastes. For instance, ^{222}Rn gas which is a daughter element of ^{226}Ra, is an alpha-emitter with a half-life of 3.8 days. Radon may seep through fractures and pores, and reach the atmosphere. When inhaled, radon gas can cause cancer.

The quantity of tailings (in terms of 10^6 m^3) from 4384 uranium mines worldwide, are listed below, country/region-wise: USA – 120; Canada – ~30; Brazil – 2.17; Australia – 48.6; Kazakhstan – 209; Uzbekistan – 30; China, India, Japan – 0.03; Germany – 161; Ukraine – 130; Russia – 54.1; France – 47.3; Czech Republic – 46.8; East European and Nordic countries – 59.15; Total 938×10^6 m^3 (source: IAEA, 2004). Remediation of mines and mill mailings site is expensive. Only USA, Germany and France have done this. Kazakhstan accounts for 23% of the world's mine and mill tailings. Fourteen countries, including Kazakhstan, former Soviet Union, Eastern Bloc countries, have yet to remediate the mines and milling sites, which is estimated to cost USD 12.9 billion.

USA disposes the uranium mill tailings in lined repositories, which are designed to last for about a thousand years, the minimum requirement being 200 years. The repositories are designed to ensure certain critical environmental conditions:

i the control of seepage of radon through the tailings – the ^{226}Ra concentrations should not exceed 0.185 Bq/g in general, and 0.555 Bq/g in the top 15 cm of soil. The concentration of radon decay products (including the background) in any habitations in the neighbourhood of the repository should not exceed 111 Bq/g (3 pCi L^{-1}), and the level of gamma radiation should not exceed the background level by more than 175.5 nGy/h.

ii prevent the dispersal of the tailings through erosion of the containment structure or through earth movements,

iii prevention of moisture infiltration which could cause groundwater pollution through seepage of fluids. The US EPA set the following standards for groundwater at the tailings sites: Combined ^{226}Ra and ^{228}Ra: 0.185 Bq L^{-1}; gross alpha particle activity: 0.555 Bq L^{-1}; Combined ^{238}U and ^{234}U: 1.11 Bq L^{-1} (equivalent to 0.044 mg L^{-1} for equilibrium); Concentration in terms of mg L^{-1} of Ag: 0.05; As: 0.05; Ba: 1.0; Cd: 0.01: Cr: 0.05; Hg: 0.002; Mo: 0.1; Pb: 0.05; Se: 0.01; NO_3– as N: 10.

3.2.2 Mineralogy and geochemistry of uranium mill tailings

The chemical composition of the uranium mill tailings would depend upon the mineralogy of the ore and the leaching process (acid or alkaline) employed. The acid leachate produced when uranium is extracted from the ore using the sulphuric acid, facilitate the release of radionuclides and toxic metals (such as, As and Pb) from the tailings to the environment. The following reaction represents the sulphuric acid leaching process:

$$UO_2 + 3H_2SO_4 + \frac{1}{2}O_2 \rightarrow [UO_2(SO_4)_3]^{4+} + H_2O + 4\,H^+$$

Table 3.2.1 Chemical composition of uranium mill tailings.

Analyte	*Canada*	*France*	*Utah (USA)**
SO_4 (µg/g)	101,000	110,522	61,100
Ca (µg/g)	51,800	52,500	63,100
Al (µg/g)	34,100	69,527	–
Fe (µg/g)	19,200	27,000	18,200
As (µg/g)	5,640	120.6	74
Pb (µg/g)	749	150.5	158
V (µg/g)	205	–	517
U (µg/g)	152	126	531
Mo (µg/g)	91	–	35
Ba (µg/g)	77	195.4	1,010
Cr (µg/g)	25	48.5	–
SiO_2 (%)	28	52.3	–
^{226}Ra (Bq/g)	74	28.4	26.3
^{210}Pb (Bq/g)	18	–	–
^{210}Po (Bq/g)	14	–	–
^{230}Th (Bq/g)	19.5	–	32.3

Source: Abdelous, 2006.

* Acid-leached ore.

Alkaline leaching with Na_2CO_3 involves the following reactions:

$$UO_2 + \frac{1}{2} O_2 \rightarrow UO_3$$

$$UO_3 + 3Na_2CO_3 + H_2O \rightarrow [UO_2(CO_3)_3]^{4+} + 4Na^+ + 2NaOH$$

In situ leaching involves the oxidation of UO_2 by ferric iron:

$$UO_2 + 2Fe^{3+} \rightarrow UO_2^{2+} + 2\ Fe^{2+}$$

After neutralization by $CaCO_3$ and/or $Ca(OH)_2$, the effluent is discharged into a waste retention plant.

The solid phases of the tailings consist of primary silicate minerals, such as quartz, feldspar, and clay which are resistant to leaching, and secondary minerals, such as, Fe hydroxides and Ca sulphate, which tend to form during processing and neutralization. The fine fraction may contain colloids, clays, sulphate salts, such as, gypsum and barite, and oxyhydroxides of Fe, Al, Mn and Si.

As is to be expected, the chemical composition of the tailings reflect their mineralogy.

The tailings contain two kinds of hazardous elements–radionuclides in the ^{238}U decay series, and toxic elements, such as, As, Pb and V. The behaviour of these elements in the process of the disposal of the tailings are described individually (Abdelouas, 2006).

3.2.2.1 Uranium

The mobility of the uranium species and complexes is strongly dependent on the ambient conditions. The geochemical behaviour of uranium in the tailings is best understood on the basis of the pE–pH diagram for the U-C-O-H system at 25°C (with total concentration of uranium at 10^{-6} M, and that of carbon at 10^{-3} M). Under oxidizing conditions, U^{6+} exists in the form of highly soluble uranyl ion (UO_2^{2+}). The mobility of uranium increases when it forms uranyl carbonate complexes, such as, $[UO_2(CO_3)_2]^{2-}$ and $[UO_2(CO_3)_3]^{4-}$. In contrast, uranium under reducing conditions exists in the form of highly insoluble U^{4+}. Generally oxidizing conditions exist in the disposal sites. However, local niches of reducing conditions could exist in the tailings due to confinement and the presence of catalytic bacteria, such *Thiobacillus ferroxidans*. Under such conditions, U^{6+} will get reduced to U^{4+}, leading to the precipitation of highly insoluble uraninite. Also, the uranyl ion gets sorbed onto Fe oxyhydroxides which are ubiquitous in the mill tailings. In the exogenous conditions, uranium gets transported in the form of uranyl carbonate $[UO_2(CO_3)]$ and hydroxide $[UO_2(OH)_2]$, uranyl humate, and phosphate complexes, and gets precipitated when reducing conditions (say, due to the presence of H_2S and organic matter) are encountered. The uranium content of the pore waters in the tailings under the oxidizing conditions (a few mg L^{-1}) are several times more than under reducing conditions (0.1 mg L^{-1}). When the sulphide minerals in the tailings get oxidized, they lead to the acidification of the pore waters. These in their turn could desorb uranyl ion from the solids, and generate high uranium concentrations in the pore waters.

3.2.2.2 *Radium-226*

The ^{226}Ra present in the ore appear to be unaffected by processing, and get passed on to the tailings. A dominant feature of the behaviour of ^{226}Ra in the tailings is its sorption and coprecipitation with Fe-Mn oxyhydroxides, gypsum, barite and amorphous silica. Sulphate-reducing bacteria play an important role in determining the concentration of ^{226}Ra in the pore waters. The concentration of ^{226}Ra is low in the pore water at shallow depth (<1.5 m water depth) as it coprecipitates with poorly crystallized barite.

At water depths of 2 m, the bacteria promote the dissolution of barite, leading to enhancement of ^{226}Ra in the pore water.

3.2.2.3 *Radon-222*

^{222}Rn gas (half-life: 3.8 days) is the daughter element of ^{226}Ra (half-life: ~1600 years). Radon is a known carcinogen. It has been reported that for each increase of 100 Bq/m^3 of radon concentration, the risk of lung cancer increases by 16% (WHO, 2005). Radon migrates through the soil by convection or diffusion. In order to prevent the migration of radon, a special cap of highly compacted clay is placed on the tailings. The clay layers are designed to give protection for about 1000 years.

3.2.2.4 *Thorium-230*

Thorium occurs only in one valence state, namely, Th^{4+}. The solubility of thorium depends upon pH. Thorium is highly insoluble under slightly acidic to alkaline conditions, and forms compounds, such as ThO_2 and $Th(OH)_4$. Its solubility increases in acid aqueous solutions ($pH < 4$). For this reason, ^{230}Th concentrations are high (1.7×10^{-8} M) in acidic tailing liquids, and low in alkaline tailing liquids (~2.4×10^{-13} M). When the tailing waters get acidified for any reason, thorium is released to the environment.

3.2.2.5 *Arsenic*

Arsenic concentrations in uranium ore deposits may be as high as 10 wt.%. Aswathanarayana (2001, pp. 314–328) gave a detailed account of the geochemical behaviour of arsenic in the environment. Arsenic can exist in three oxidation states: metalloid (o), trivalent (+3, –3), and pentavalent (+5). The toxicity of arsenic is highly speciation-dependent, and increases in the following order: elemental < organic < arsenates < arsenites < arsines. The arsenate $(ASO_4)^{3-}$ species are strongly sorbed onto clays, Fe-Mn oxides/hydroxides, and organic matter. The amount of sorption is determined by the concentration of arsenic species, time and Fe-Mn content of the tailings. Arsenite salts are 5–10 times more soluble than arsenate salts. Reducing conditions enhance the proportion of As(III), in which form it is more available and more toxic. Bacteria can accelerate the oxidation of arsenite to less soluble arsenates. They can also bring about methylation, in the form of As(III) methyl derivatives.

A partial pE–pH diagram for dissolved arsenic species (Appelo & Postma, 1996, p. 249) shows the boundaries between the As(V) species of $H_2AsO_4^-$, and As(III) species of H_3AsO_3.

In the course of processing, lime is added for pH control. Consequently, the pore waters in the tailings may have a pH of more than 7 or 8. Also oxidizing conditions may prevail. Under these circumstances, As may exist in the form of $HAsO_4^{2-}$, with As concentration of 5–15 mg L^{-1}. This concentration is much higher than the US NRC groundwater standard for tailings (0.05 mg L^{-1}). Arsenic exists in the pentavalent form in the surface waters which are characterized by high Eh and slightly acid pH. In the groundwaters which are characterized by low Eh and near neutral pH, arsenic species tend to remain in the soluble form. The dimensions of the contaminant plume of Arsenic depend upon the geochemistry of the surface and groundwaters, the biogeochemistry of the site and the nature of the soils (amount of Fe oxyhydroxides present in the soils) at the site.

A number of factors have to be taken into account to control the release of hazardous elements, U, Th, Ra, Rn, and As to the environments, such as, the physical stability of the tailings disposal facility, the performance of the engineered covers, and the chemical stability of the mineral phases with which the toxic elements are associated. The presence of Fe oxyhydroxides (which sorb the toxic elements) and acid pore waters (which solubilise the toxic elements) determine the dynamics of movement of toxic elements. It is critically important that toxic elements leached from the tailings should not be allowed to reach levels where they constitute a threat to the ecosystem (plants, animals, humans, etc.).

3.2.3 Environmental impact of uranium mines and mill tailings

Tailings may be considered as "manmade soil" with properties between those of sand and clay. All the issues connected with tailings have been comprehensively dealt with in the Proc. Int. Symp. on Tailings and Mine Wastes (2002).

The most serious problem facing the mining industry presently is the enormous quantity of tailings (about 18 million m^3/y), which incidentally is of the same order as the quantity of sediment discharges into the oceans. As progressively lower grades are worked, the mass of mine tailings is expected to double in the next 20–30 years. The environmental risks from mine tailings include: Chemical contamination, causing damage to the ecosystem; Habitat smothering; Catastrophic system collapse due to earthquakes or torrential rains which may undermine the structural stability of the tailings deposit; Landform changes; Water turbidity and siltation; Socioeconomic changes caused by changes in resource use (Ellis and Robertson, 1999). It is not without significance that the failure of the tailings dams figure prominently in the list of major accidents related to the mining industry (Aswathanarayana, 2003, pp. 285–286). A tailings dam fails when the peak flow exceeds the hydraulic capacity of the spillways, decants and diversions. The resultant liquefaction and the release of the stored tailings can cause great damage to life, property and the environment.

During the early stages of uranium mining when the tailings disposal facilities were not protected with proper liners, there have been instances of significant contamination of soils, surface waters, groundwaters and ecosystems because of leakages from the disposal facilities. In some cases, coarse sands in the tailings were made use of make concrete which was used in the building construction. People who reside in such buildings are exposed to radon and its daughter products which are carcinogenic.

Environmental damage from the failure of the containment structures may be chronic (e.g. dispersal of radioactive dust from the dry tailings) or catastrophic (caused by slope instability, seepage, overtopping and earthquakes). When the tailings dam at Church Rock, New Mexico, USA, got breached, it released 370,000 m^3 of radioactive water, and 1000 tonnes of contaminated sediment, and polluted the waters of River Puerco for 110 km (IAEA, 2004).

When the groundwater is acidified in the process of leach mining of uranium, it is an extremely difficult task to restore the pH of the groundwater to neutral level. The acid leachate plume containing radionuclides and heavy metals, will move along the groundwater and spread the contamination. Jarosite $[KFe(SO_4)_2(OH)_2]$ which will get precipitated in the process of in situ leach mining with H_2SO_4, tends to hold significant contents of contaminants, such as As, Pb, Hg, Cu, Zn, Cr, Se, ^{226}Ra. These may get released into the environment during the flushing of the aquifer which is characterized by the presence of jarosite.

The health hazards to humans due to uranium tailings arise from radon and contaminated surface waters. It has been reported that the population dose near six old uranium mines in Spain (3.2–5.1 mSv/y) is higher than the national average of 2.6 mSv/y. This has resulted in the greater incidence of lung cancer in the area than the national average. When the tailings are used in the construction of habitations or when houses have been built over tailings-derived landfill, very high concentrations of indoor radon (20,000 Bq/m^3) have been reported. As against this, the generally acceptable limits for indoor radon concentrations are 200–400 Bq/m^3 (5.4–10.8 $pCi\ L^{-1}$).

3.2.4 Acid Mine Drainage (AMD)

Acid Mine Drainage (AMD) gets generated due to the oxidative dissolution of the iron-containing sulphide minerals, such as pyrite in the tailings. Under oxidizing conditions and in the presence of catalytic autotrophic bacteria, such as, *Acidithiobacillus ferroxidans* and *Acidothiobacillus thiooxidans*, pyrites gets oxidized to sulphuric acid as per the following equation:

$$4FeS_2 + 15O_2 + 2H_2O = 2Fe_2(SO_4)_3 + 2H_2SO_4$$

The low-pH waters dissolve substantial quantities of Fe oxyhydroxides, carbonates and other secondary phases, which carry radionuclides and heavy metals. If the containment structures are not properly lined, the contaminants migrate into local aquifers. The spreading plume that originates from the tailings move at the rate of several tens of metres per year (von der Heyden and New, 2004). In the case of alkaline mill tailings, the migration of uranium takes place in the form of stable uranyl complexes, such as, $[UO_2(CO_3)_2]^{2-}$ and $[UO_2(CO_3)_3]^{4-}$. The contaminated groundwater plume near the tailings pile near Tuba City, Arizona, USA, which contains not only uranium, but also nitrate (~1 g/l) and sulphate (~2 g/l) has been moving at an average rate of about 15 m per year (Abdelouas et al., 1998).

Since the supply of both oxygen and water are necessary for the generation of AMD, an obvious way to prevent the formation of AMD is to block the entry of oxygen and water to the waste pile. MIMI (1998) and Angelos and Niskanen (2001) described several rehabilitation options for the waste dumps. The common purpose of all of them is to limit the transport of oxygen and air into the waste.

3.2.4.1 Case history of Elliott Lake (Canada) uranium tailings

Davé and Paktunc (2001) gave the case history of the waste management and decommissioning of the pyritic uranium tailings of the Elliott Lake uranium mine, Ontario, Canada. The shallow groundwater of the Stantock tailings show that along central longitudinal direction of the Stanrock tailings, the groundwater is characterized by low pH (1.8–4), high total acidity (1,000–12,000 mg $CaCO_3$/l), and high concentrations of dissolved SO_4 (2,000–14,000 mg/l), and Fe (500–6000 mg/l). At the central site, near the surface water streams, the pH of the groundwater is high (~6), and the concentrations of total acidity (~50 mg $CaCO_3$/l), SO_4 (~2200 mg/l),and Fe (~100 mg/l) are low. Davé and Paktunc (2001) conclude that covering the tailings with a vegetated cover layer, and raising the water table can effectively suppress acid generation.

3.2.4.2 Case history of Aznalcóllar (Spain) tailings dam spill

As a consequence of the failure of the Aznalcóllar acidic pyrite tailings dam in Seville, Spain, a spill of 5.5×10^6 m^3 of acidic water and 1.3×10^6 m^3 of heavy metal (As, Pb, Cd and Zn) bearing tailings occurred on 25 April 1998 and covered an area of 4248 Ha along the Agrio and Guadiamar river valleys. The contaminated soil was removed in 1999. More than a year after the spill has occurred, the heavy metal concentrations were still 7 to 55 times higher than the pre-spill levels. River waters 2.6 km downstream of the mine were characterized by low pH (~4.4) and high sulphate concentrations (~1 g/l).

The Algerian mouse (*Mus spretus*) was used to monitor the biological consequences of the Aznalcóllar spill. The concentration of the tailings metals (Pb, Cd, As) in the liver and kidneys of the biomarkers in the Doñana National Park, clearly show the effects of the pollution. Accumulations of As, Cd and Zn in the tubers of *Scirpus maritimus* L. in the Doñana marshes, which are a source of food for the local geese, have been reported.

The concentrations of Cd (0.25 mg/kg) and Zn (61 mg/kg) in the tuber tissues are markedly higher relative to the control areas (Cd: 0.02 mg/kg; Zn: 22 mg/kg).

The toxicity of As on microbial activity is evaluated on the basis of DHA (dehydrogenase activity) – high DHA indicates high microbial activity. Fernández et al. (2005) found that the arsenic-bearing tailings are reducing the oxidative capacity of the soil, and thereby affecting the food chain.

3.2.5 Modeling of contaminant impact

The Swedish Radiation Group (Camus et al., 1999) developed comprehensive models for the long-term impact of the contaminants from the mill tailings, covering multiple contaminants, multiple pathways, and multiple environmental receptors. They found that release of radon and deposition of the contaminated dust from the atmosphere affect the humans the most. According to the Group, the contribution to the total dose is attributable to (i) ingestion of leafy vegetables grown in soils contaminated with radioactive dust: 71–79%, (ii) dust and gas inhalation: 12–20%, (iii) external exposure from soils: 3–9%, and (iv) ingestion of beef (4–7%).

3.2.6 Conclusion

It is important to dispose the tailings hermetically, using bottom liners and caps on tailings, to last for 200 to 1000 years. In situ bioremediation technologies are being developed to optimize the containment process. In all cases, monitoring of groundwater has to be carried out for tens of years. There is need to understand the role of microorganisms on the behaviour of radionuclides and heavy elements in regard to the tailings. We know that while iron and sulphur-oxidising bacteria may cause the rise in radionuclide concentrations through acidification, metal- and sulphate-reducing bacteria bring about the precipitation of radionuclides, through the reduction of U^{6+} to U^{4+}.

3.3 SPENT NUCLEAR FUEL[2]

Radioactive wastes are classified depending upon the activity content and thermal heat load. Low and medium-level wastes are routinely disposed in most countries. More than 95% of the radioactivity produced by reactors comes under High Level Wastes (HLW). A 1000 MW light-water reactor produces about 25 t of spent fuel per year. After the reprocessing of the spent fuel, about 3 cubic meters of vitrified waste is produced per year. About 5000 tonnes of spent fuel are reprocessed in France, U.K. and Russia. The global cumulative experience is 80,000 t over 50 years (WNA, 2007).

3.3.1 Nuclear Fuel Cycles

The Nuclear Fuel Cycle includes the conversion of uranium into gaseous UF_6, enrichment of ^{235}U (from ~0.7% to 3.5–5%), fabrication of fuel rods by encasing UO_2 pellets in metal tubes, power generation through fission in the nuclear reactors, and storage of the spent nuclear fuel (SNF) for reprocessing or deep geologic disposal.

Spent Nuclear Fuel (SNF) is the primary waste form resulting from the nuclear energy production. The nuclear fuel is generally in the form of UO_2, and sometimes-metallic uranium. The SNF arising from UO_2 is a fine-grained (5–10 μm), polycrystalline aggregate containing fission-produced and transuranium elements in concentrations of 4–6% (Bruno & Ewing, 2006).

Low-enriched uranium fuel, with ^{235}U enriched to 3 to 5%, is used in light water reactors (LWR).

Ewing (2006) gave a lucid exposition of the concept of "Open" and "Closed" nuclear fuel cycles. The Open Cycle (Fig. 3.3.1) treats the Spent Nuclear Fuel (SNF) as a waste, which is directly disposed of in a geological repository, without any effort to reclaim the remaining ^{235}U or the newly created ^{239}Pu (by neutron capture reactions on ^{238}U, followed by beta decay). USA follows this method. The nuclear burn-up of

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[2] This chapter draws extensively from Bruno and Ewing (2006).

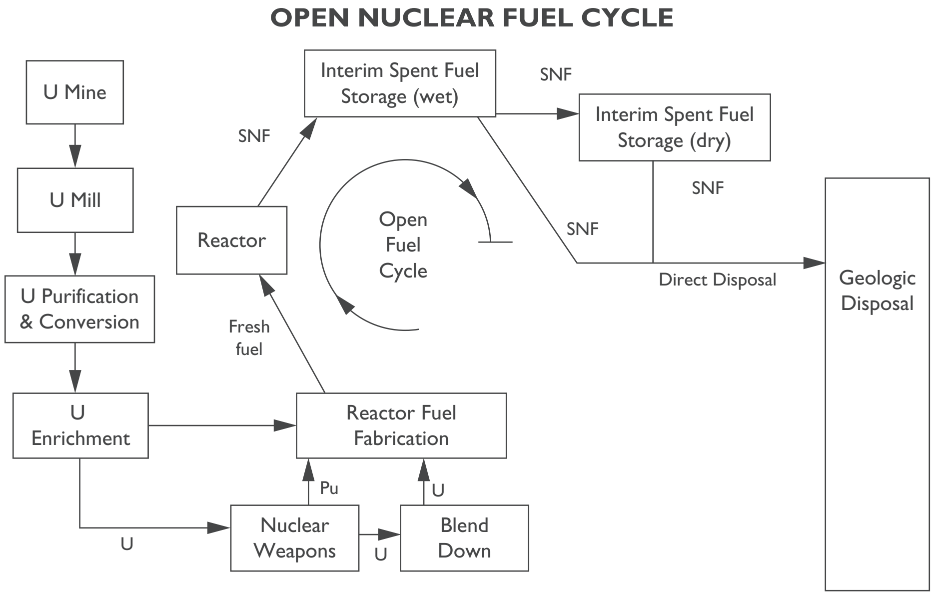

Figure 3.3.1 Open Nuclear Fuel Cycle.

Source: Ewing, 2006.

uranium generates 40 Megawattdays/kg (MWd/kg of U) of energy, and results in the conversion of the initial U in the fuel to ~1 atomic percent of transuranium elements, mainly ^{239}Pu, and ~3 atomic percent of fission products, such as ^{137}Cs, and ^{90}Sr. The Spent Nuclear Fuel (SNF) still contains fissile nuclides, such as ^{235}U and ^{239}Pu generated in-reactor by neutron capture reactions. A typical light water reactor (LWR) will create 20 t of SNF per year.

In the Closed Nuclear Fuel Cycle (Fig. 3.3.2), the Spent Nuclear Fuel (SNF) is reprocessed to retrieve approximately 99% of the fissile nuclides. The ^{239}Pu and ^{235}U thus retrieved are refabricated into fuel elements and "burned" in the reactor. Several cycles of reprocessing can be performed, but would result in the accumulation of contaminants, such as Cm and Am, which would render reprocessing difficult. At some stage, the high-level wastes had to be disposed in a geological repository.

PUREX (Pu-U-Recovery – Extraction) is the most commonly used reprocessing technology, and involves the solvent extraction process with oxidation-reduction chemical reactions. Minimal reprocessing, however, reclaims only fissile ^{235}U and ^{239}Pu, leaving behind a high-level waste composed of a complex mixture of fission products, and actinides such as Np, Am and Cm. The high-level waste is vitrified in a borosilicate glass. Advanced reprocessing technologies are being developed for the separation of specific radionuclides, which can then be immobilized in durable waste forms. The usual practice is to keep the SNF in interim storage for a few years prior to reprocessing. Dismantled nuclear weapons have emerged as an important source of fissile

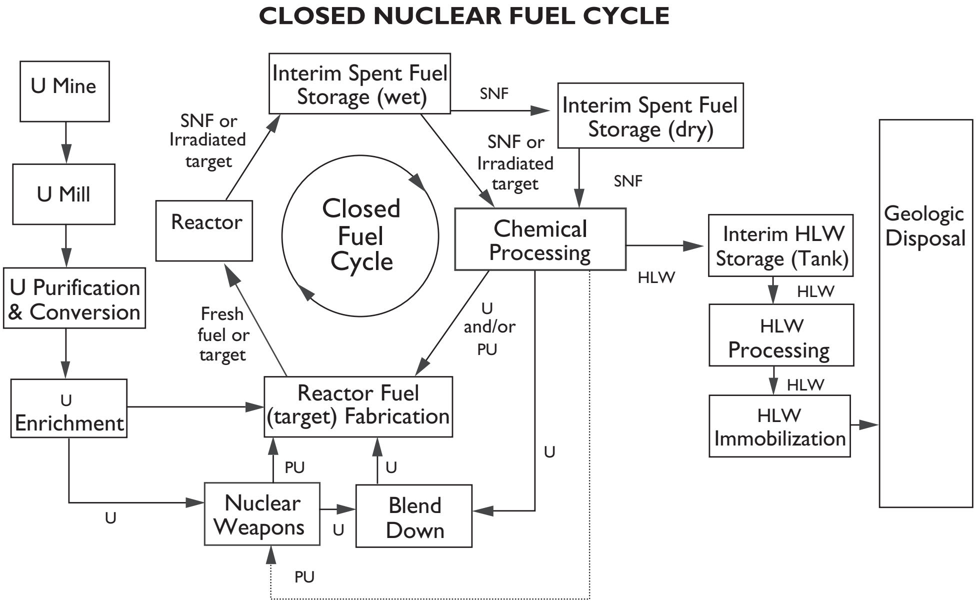

Figure 3.3.2 Closed Nuclear Fuel Cycle.

Source: Ewing, 2006.

material. Thus, highly enriched ^{235}U can be blended down, or ^{239}Pu could be mixed with uranium to form mixed-oxide fuel (MOX). Efforts are being made to develop new reactor designs in which not only ^{235}U and ^{239}Pu, but also a larger proportion of heavier transuranium elements can be "burned".

In other words, whether the Fuel Cycle is Open or Closed, there has to be provision for the disposal of the high-level wastes at some stage. "The composition, radiotoxicity and the relative proportions of radionuclides in the material to be disposed, would depend upon the type of reactor, the extent of burn-up and the reprocessing strategy" (Ewing, 2006, p. 322).

3.3.2 Nuclear Fuel Fabrication

Spent Nuclear Fuel (SNF) is the primary waste form resulting from the nuclear energy production. The nuclear fuel is generally in the form of UO_2, and sometimes metallic uranium. The SNF arising from UO_2 is a fine-grained (5–10 μm), polycrystalline aggregate containing fission-produced and transuranium elements in concentrations of 4–6% (Bruno & Ewing, 2006).

Low-enriched uranium (LEU) fuel, which has ^{235}U enriched to 3 to 5%, is used in light water reactors (LWR). Some research reactors use highly-enriched fuel (HEU) in which ^{235}U is enriched to >20%. Highly enriched (>85% ^{235}U) fuel may be extracted from dismantled nuclear weapons, and may be blended for use in LWR. The Canadian CANDU reactors which use heavy water as a moderator and coolant, use natural uranium as fuel. ^{233}U and ^{239}Pu which are "bred" from ^{232}Th and ^{238}U respectively by neutron capture, may also be used as reactor fuels.

Two types of nuclear reactions (fission, and neutron capture and beta decay) occur when the fuel in LWR is exposed to thermal neutron flux (~0.03 eV):

Fission:

$$^{235}\text{U} + {}^{1}\text{n}_0 \rightarrow \text{fission fragments} + 2\text{–}3 \text{ neutrons } (1\text{–}2 \text{ MeV}) + \text{energy}$$

Neutron capture and beta decay:

$$^{238}\text{U} + {}^{1}\text{n}_0 \rightarrow {}^{239}\text{U} \rightarrow {}^{239}\text{Np} \rightarrow {}^{239}\text{Pu}$$

Most of the fission-product isotopes produced in the reactors have short half-lives, and therefore they become virtually extinct in a few days or weeks. ^{239}Pu is the most abundant transuranium ($Z > 92$) element to form as a consequence of the neutron capture and beta decay. Thus, the concentration of ^{239}Pu in the fuel increases with time, and can be fissioned to produce energy. Also, by using high-energy (>1 MeV) "fast" neutrons, ^{238}U and the "minor" actinides could be fissioned. "The final composition of the fuel depends upon the initial fuel type, chemical composition, the level of enrichment of ^{235}U, the neutron energy spectrum, and the "burn-up" or the amount of fission" (Bruno and Ewing, 2006). The typical burn-up yields 35–45 MWd/kg of U, and efforts are being made to improve this figure. Generally a reactor produces about 20 tonnes of spent nuclear fuel. There are about 430 reactors in the world, and the global inventory of spent nuclear fuel has been estimated to be about 270,000 tonnes. Out of this, USA has spent fuel inventory of about 62,000 t.

Fissile nuclides ^{235}U and ^{239}Pu which are reclaimed from the Spent Nuclear Fuel through chemical processing, can be fabricated into mixed oxide fuel (MOX), by mixing 5–10% ^{239}Pu with uranium. A clever way of burning ^{239}Pu and minor actinide elements alone without creating more transuranium elements is to fabricate the Inert Matrix Fuel (IMF) using inert ZrO_2 (in place of uranium) and ^{239}Pu.

3.3.3 Radioactivity of Spent Nuclear Fuel

In the natural uranium ore, uranium exists in secular equilibrium. With its daughter elements. In the process of converting the uranium ore to "yellow cake" (U_3O_8), the daughter elements of uranium get removed, and hence the uranium fuel is less radioactive than the uranium ore. The U_3O_8 is converted into uranium hexafluoride gas which is enriched in ^{235}U by gaseous diffusion or centrifugation. The enriched UF_6 gas is converted chemically into $UO_{2.25}$. Nuclear fuel assemblies are fabricated by stacking cylindrical pellets of UO_2 (8–10 mm in diameter and 9 to 15 mm thick) in corrosion-resistant cladding material, such as zirconium alloys. Inert helium gas is pumped in to fill the empty spaces within the fuel assembly. When the fuel pellets expand a little during irradiation, the helium gas will take care of it. The physical structure of the fuel assembly depends upon the reactor design, and may weigh about 500 kg.

The burn-up in the reactor leads to the production of 3–4 atomic percent of fission products (e.g. ^{129}I, ^{131}I, ^{137}Cs, ^{90}Sr), transuranium elements (e.g. ^{239}Pu, ^{237}Np, ^{241}Am), and activation products (e.g. ^{14}C, ^{60}Co, ^{63}Ni) in the spent fuel assemblies. Consequently, the radioactivity of the spent fuel goes up a million-fold (~10^{17} Bq/tonne). One year after discharge from the reactor, the radiation dose (one million sieverts/hr) of the spent nuclear fuel would still be high enough to cause the death of a person when exposed to it for less than a minute at the distance of one meter (the background dose is of the order of three mSv/y). The Spent Nuclear Fuel should necessarily be handled remotely because of the extreme danger of exposure.

Fission products, such as, ^{137}Cs, ^{90}Sr, which are characterized by short half-lives of the order of 30 years, and emit highly penetrating β and γ radiations, are mainly responsible for the thermal heat from the fuel (1300 watts/tonne of fuel after 40 years). The less penetrating α radiation is emitted by very long-lived actinides, such as ^{239}Pu (half-life: 24,100 years) and ^{237}Np (half-life: 2.1 million years).

Figure 3.3.3 (source: Hedin, 1997) shows how the relative radioactivity of the SNF with a burn-up of 38 MWd/kg of U decreases with time. In the first 100 years, the radioactivity is dominated by fission products and by actinides thereafter. Only 0.01% of the activity one month after removal will remain after 10,000 years. After hundreds of thousand years, the radioactivity of SNF will be comparable to the uranium ore itself. The concentrations (in ppm) of various elements in a low burn-up (30 MWd/kg U) Spent Nuclear Fuel are as follows (Buck et al., 2004): Xe – 5657; I – 259; Cs – 2605; Sr – 794; Ba – 1750; Se – 58; Te – 529; Zr – 3639; Mo – 3497; Tc – 799; Ru – 2404; Rh – 484; Pd – 1684; Ag – 92; La – 1269; Ce – 2469; Pr – 1161; Nd – 4190; Sm – 815; Eu – 155; Gd – 142;

^{237}Np – 468; Pu (total) – 9459; Am (total) – 484; Cm (total) – 39.

High-level radioactive waste is a hazardous waste with a difference. While for normal hazardous wastes (e.g. chemical wastes), the magnitude of the hazard remains virtually unchanged with time, the magnitude of the hazard in respect of the high-level radioactive wastes changes with time, as some radionuclides become extinct, and as

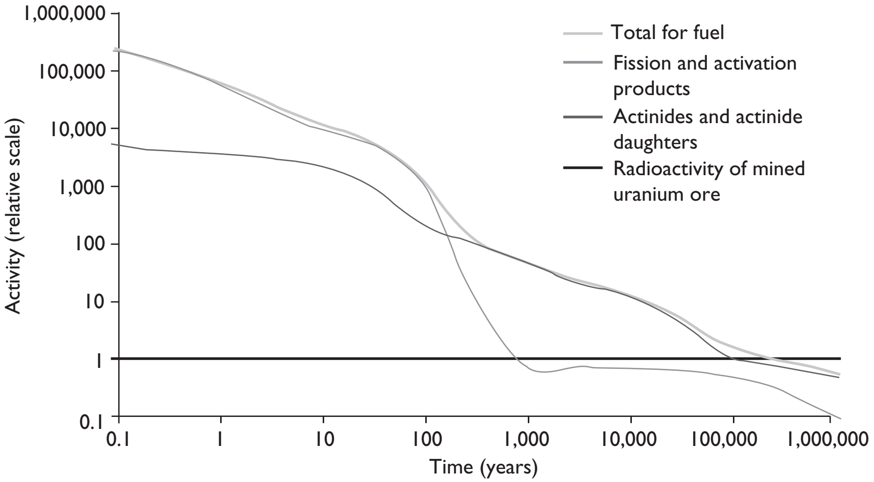

Figure 3.3.3 Relative radioactivity of Spent Nuclear Fuel.

Source: Hedin, 1997.

new radionuclides which form due to radioactive decay, have toxicities and mobilities different from their parent elements. For instance, the concentration of the radioactive nuclide, ^{237}Np which is the decay product of ^{241}Am, increases with time.

Radionuclides characterized by high radiotoxicity, high geochemical mobility and long half-life, have the greatest environmental impact in a geologic repository. Examples are: ^{99}Tc (half-life: 200,000 years.), ^{79}Se (1 million years), 239 Pu (24,100 years), ^{237}Np (2.1 million years), ^{235}U (700,000 yrs.); Activation products, such as ^{36}Cl (300,000 years) ^{14}C (5700 years). It is therefore an extremely difficult task to accurately predict the radiotoxicity and environmental demand on the geologic repository of SNF.

3.3.4 Structure and Composition of the Spent Nuclear Fuel

At the end of the useful life of a nuclear fuel assembly, about 95% of the original UO_2 would still be there in SNF. The reminder would consist of Actinides (23%), rare earths (22%), 4d metals (20%), gases (13%), zirconium (8%), alkali earths (6%), alkalis (6%) and others (2%) (Buck et al., 2004). These materials occur in different forms. Gaseous fission products, such as Xe and Kr, occur in the form of fine bubbles in the fuel grains. Metallic fission products, such as, Mo, Tc, Ru, Rh, and Pd, occur as very fine (nanometre-sized) metallic precipitates ($\varepsilon-$ particles). Some elements, such as, Rb, Cs, Ba and Zr form oxide precipitates. Rare earth elements form solid solutions with the UO_2 fuel. Transuranium elements substitute for uranium in UO_2 (Kleykamp, 1985).

The pellets are highly inhomogeneous. There is a steep thermal gradient within a pellet – the temperature may be as high as 1700°C at the centre, decreasing to 400°C at the rims. This causes thermal excursions, resulting in the coarsening of the grains, extensive micro-fracturing, and the migration of the volatile elements, such as, Cs and I, to grain boundaries, fractures and the tips of the pellets. The burn-up is higher at the edge of the pellet, and this leads to higher concentrations of ^{239}Pu at the fuel edge, increase in porosity, and reduction in the size of the individual grains. Figure 3.3.4 (Source: Buck et al., 2004) gives a schematic illustration of the microstructure of the spent fuel, and the distribution of actinides and fission products following the burn-up in a reactor.

In sum, the spent fuel has complex phase assemblages and chemistry, which is determined by its thermal history, neutronics and initial composition of the fuel (Bruno and Ewing, 2006).

3.3.5 Behaviour of SNF in a geologic repository

For purposes of monitoring the behaviour of SNF in a geologic repository, SNF is best characterized as "a complex, redox sensitive and polycrystalline ceramic". Although ~95% of the SNF is composed of uranium, it is the geochemical mobility of the rest 5% of radionuclides that determine the geochemical behaviour of the SNF in a geologic repository. These radionuclides occur in the form of inert gases and stable precipitates, and are inhomogeneously distributed in the SNF. As a consequence of radioactive decay of the radionuclides in the SNF, the thermal and radiation fields in the repository change with time. It may happen that over periods of hundreds of thousands of years, the radionuclides in the repository may travel some kilometers.

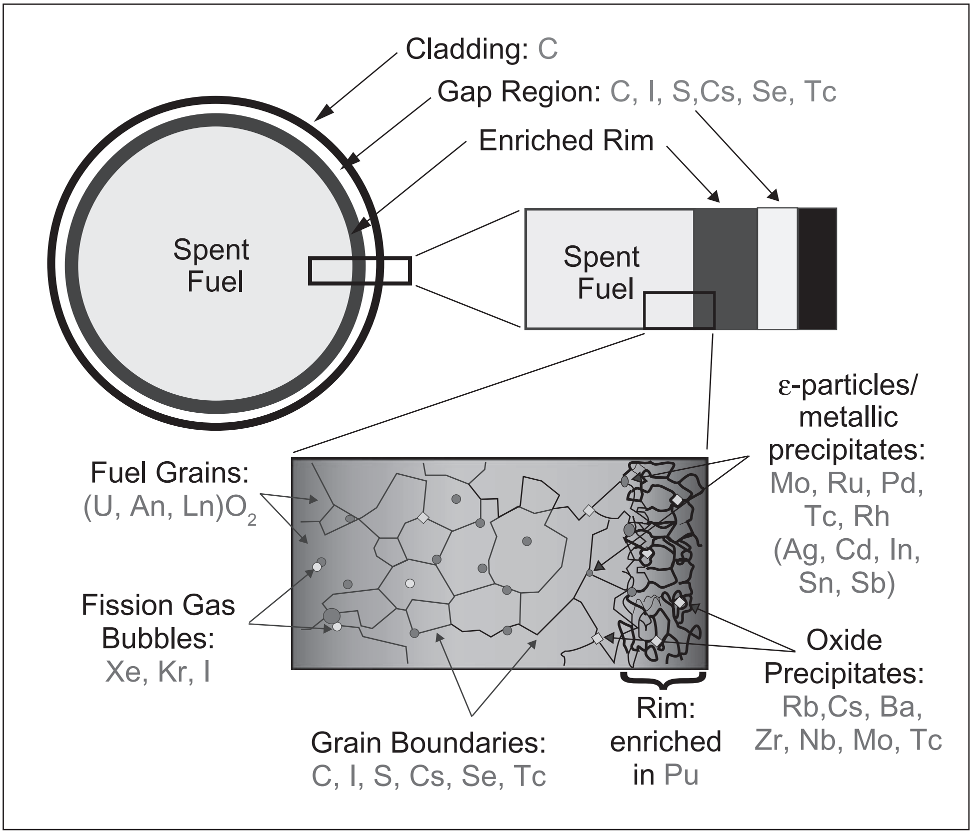

Figure 3.3.4 Microstructure of the Spent Nuclear Fuel.

Source: Buck et al., 2004.

In order to design a system to minimize the risk to the humans as a consequence of this complex situation, scientific knowledge is needed in respect of the following: (i) detailed knowledge about the SNF after it is taken out from the reactor, and how it is going to evolve with time, (ii) how the thermal and radiation fields of SNF would respond to the evolving geochemical and hydrologic conditions, (iii) mobility of the radionuclides in the SNF in the near-field and far-field environments of the geologic repository, and (iv) radiation risk to humans as a consequences of the pathways to man of individual radionuclides (Bruno and Ewing, 2006).

The processes of dissolution and alternation of UO_2 in the spent fuel under reducing disposal conditions have been studied by Grambow et al. (2000), and under oxidizing disposal conditions by Ewing and Peters (2005).

Figure 3.3.5 (source: Poinssot et al., 2005) shows how the spent fuel undergoes alteration when it is breached, assuming the presence of water. The fuel assembly is of the kind used in light water reactors. FP – Fission Products; RN – Radionuclides.

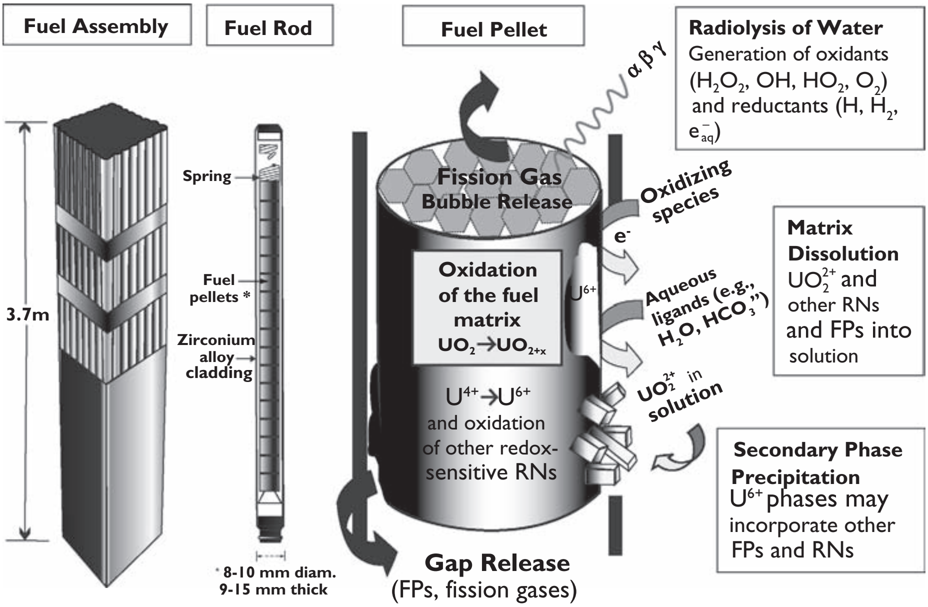

Figure 3.3.5 Alteration of SNF upon breaching of fuel rod.

Source: Poinssot et al. 2005.

Four processes are involved:

i Radiolysis of water by alpha, beta and gamma radiations, leads to the generation of oxidants (such as, H_2O_2, OH, HO_2, O_2) and reductants (such as, H, H_2, e^- aq). Radiolysis is less important under oxidizing conditions. During the near term of a some hundreds of years, beta and gamma radiation dominate the radiation field. In the longer term of over a thousand years, it is the alpha decay that would cause the radiolysis.

ii Oxidants produced by radiolysis or those that may be already present, may oxidize UO_2 to UO_{2+x}, where x may be between 3 and 4. Additional oxygens enter the UO_2 structure and occupy the interstitial spaces.

iii The alteration and dissolution of the fuel matrix involving UO_2, involves the oxidation of U(IV) to U(VI). The oxidized U(VI) at the fuel surface gets dissolved in the groundwater, and forms complexes with oxygen-containing ligands, such as, (HCO_3^-) and (OH^-).

iv Precipitation of secondary U(VI) phases, under oxidizing conditions.

In Europe, geologic disposal concepts are being developed for the Fennoscandian granite sites at Olkiluoto, Finland, and Főrsmark, Sweden. Reducing conditions prevail because of saturated flow *below* the water table. Under these conditions, radiolysis of water is the only source of oxidants. UO_2 in the spent fuel will tend to remain stable under reducing conditions. The canister and the clay backfill are designed to prevent the UO_2 in the spent fuel from coming into contact with water,

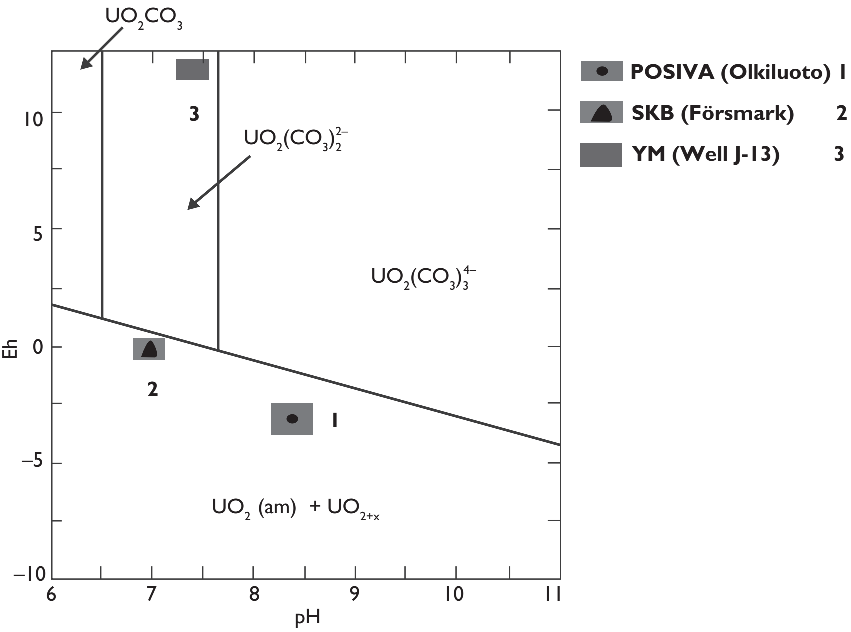

Figure 3.3.6 Eh–pH Diagram of the uranium system in relation to the redox conditions of the potential repository sites.

Source: Guillaumont et al. 2003.

thereby precluding the possibility of generation of oxidants by the radiolysis of water.

On the other hand, the proposed repository in the Yucca Mountain volcanic tuff site in Nevada, USA, is located in the unsaturated zone *above* the groundwater table, under *oxidizing* conditions. Nuclear waste is chemically unstable under these conditions. It is critically important to prevent the access of water to the waste package.

Figure 3.3.6 (source: Guillaumont et al., 2003) depicts the Eh–pH stability diagram of $UO_{2(solid)}$ in average groundwater compositions, $[CO_3^{2-}]_{tot} = 10^{-3}$ M; and $[U] = 10^{-8}$ M, on which the "stability field" of the repository concepts at different sites, namely, Olkiluoto, Finland, and Főrsmark, Sweden (reducing conditions) and Yucca Mountain, USA (oxidizing conditions) are superimposed.

3.3.6 Natural Fission Reactors of Oklo, Gabon, West Africa

There are two sources of information (laboratory studies, and the natural reactors of Oklo, Gabon) for projecting the long-term stability of UO_2 in the spent nuclear fuel, and the mobility of fission products and transuranium elements, under different geologic settings. Uraninite, $UO_{2+\alpha}$, and UO_2 in the spent nuclear fuel, have similar structures, and similar geochemical behaviours. When U(IV) gets oxidized into U(VI) under oxidizing conditions, similar alteration products come into existence. Thus, laboratory investigations could provide insights regarding the behaviour of the spent nuclear fuel in the repositories (Bruno et al., 2002).

Remnants of spontaneous fission that took place in a uranium deposit in Oklo, Gabon, two billion years ago, provide a unique natural "window" to view the fission processes, spent fuel, and the dynamics of the fission products and actinide elements (Janeczek, 1999). These reactors are thus capable of indicating the shape of things to come for the spent fuel in the repository. The reactors were of small size (a few metres). Two billion years ago, the uranium ore in Oklo contained ^{235}U at the concentration level of 3.5%, which is comparable to the concentration of ^{235}U in the nuclear fuel in the light water reactors. Water and in some cases, carbon, served as moderators. By chance, there was no vanadium to absorb the neutrons. Quartz in the surrounding sandstone served as reflector. The temperature of the reactors was 400–500°C in the peripheries, and about 1000°C in the centre. Small hydrothermal systems came into existence around the reactors. The reactor got turned on when water, the moderator, entered the pores of the rock. The reactor got turned off when the heat in the reactor, evaporated the water and drove it out. Later when the reactor cooled sufficiently to allow water to enter the pores, the process started once again. It has been estimated that these reactors fissioned about ten tonnes of ^{235}U over a period of several hundred thousand years. Naudet (1991) gives a fascinating account of these fossil reactors.

There are a number of analogies between the laboratory observations of spent fuel and what has been found on the ground in the case of the Oklo reactors: capture and incorporation into apatite of ^{239}Pu (which is now in the form of its decay product, ^{235}U), and the presence of micrometer to nanometer-sized metal alloy inclusions of Mo, Ru, Pd, Tc, and Rh – the epsilon phase. Thus, many of the processes of dissolution, alteration and retardation processes observed in the case of UO_2 in the spent nuclear fuel could be found in Oklo, thus strengthening our confidence in predicting the behaviour of the spent fuel over hundreds of thousands of years (Bruno et al., 2002).

3.3.7 Neptunium Mobility and its implications for SNF disposal

Burns and Klingensmith (2006) reviewed Neptunium mobility.

^{237}Np is the decay product of ^{241}Am, and so its abundance continues to increase for hundreds of years after the spent nuclear fuel is removed from the reactor. Because of its long half-life of 2.14 million years, ^{237}Np is a significant contributor to the total dose of radioactivity in the geologic repository. Neptunium has three oxidation states (4+, 5+ and 6+). Amongst the three oxidation states, the pentavalent state of Np is most soluble and is most mobile in groundwater. Hence the importance of the performance of Np^{5+} in the context of the spent fuel behaviour in the repository under oxidizing conditions in the unsaturated zone.

The neptunyl ion $(NpO_2)^+$ is geometrically very similar to uranyl ion $(UO_2)^{2+}$. Minerals, such as, bequerelite, $Ca[(UO_2)_3O_2(OH)_3]_2(H_2O)_8$ and uranophane $Ca[(UO_2)SiO_3(OH)]_2(H_2O)_5$, which form due to the alteration of uraninite in uranium deposits, are to be found in the alteration products of the spent fuel in the laboratory investigations. Because of their similar polyhedral geometries, Np^{5+} can substitute for U^{6+} in bequerelite and uranophane. The charge balancing between the two ions is satisfied by the substitution of (say) Am^{3+} in place of Ca^{2+} in the interlayer of single crystals of these minerals. The intense radiation of neptunium may reduce the crystallinity and affect the stability of uranyl minerals. Hence the long-term fate of the uranyl minerals which have incorporated Np^{5+} in their structures thus become important in understanding the behaviour of the spent fuel in the repository.

3.4 VITRIFICATION OF RADIOACTIVE WASTES

3.4.1 Geological issues relevant to the siting of waste repositories

Disposal of radioactive wastes is the most complicated task that a geotechnical engineer has to accomplish. Attewell (1993, p. 199) and Aswathanarayana (1995, pp. 221–223) gave a concise account of the issues involved. Uranium mines, nuclear fabrication facilities, nuclear reactors, reprocessing plants, etc. produce radioactive wastes. They are generally classified as low-level, medium or intermediate level and high level wastes, depending upon the nature and content of radionuclides, rate of decay, rate of heat generation and methods of treatment. Low-level radioactive wastes are produced in the course of uranium mining, concentration and conversion plants, and liquid and gaseous effluents. Intermediate wastes include fission products from fuel fabrication and spent-fuel reprocessing plants. Spent reactor fuel and cladding hulls constitute high-level wastes. How the wastes form and how they need to be managed are described in detail in Sections 3.2 and 3.3.

The following criteria have to be taken into consideration in planning the geological isolation of radioactive wastes: (1) The package should remain stable for at least 1000 years, (2) It should be isolated from the groundwater as long as possible, (3) It should be so designed that there is the least possible exchange with groundwater, should contact be accidentally made with groundwater, and (4) The groundwater path between the package and the biosphere should be such that the radionuclides released from the waste package will not reach the biosphere for at least 1000 years after release.

Since the overriding consideration is the avoidance of contact with groundwater and biosphere, uninhabited, stable (i.e. non-seismic) areas of low rainfall (say, less than 100 mm), without fossil groundwater, are to be preferred, other things being equal.

Low-level wastes may be disposed of in trenches dug in impervious material, such as clay.

Intermediate level wastes may have to be buried in tunnels, boreholes, at depths down to 1000 metres. The disposal site may be on land, with access from a land base, or under the seabed with access from a land base or an offshore structure. According to the UK Nuclear Radioactive Waste Executive (NIREX) (as quoted by Attewell, 1993, p. 198), the following kinds of locations are suitable:

1 Small offshore islands whose fresh water regime is not connected to the mainland. If the waste is disposed of below the interface of fresh water and salt water, there will be little chance of contact with groundwater.
2 Hard rock, such as granite, in a situation of low relief. Low relief would preclude any significant groundwater movement. Fractured and jointed units should be

avoided as groundwater could move through the openings. Where the granite is highly weathered, kaolinisation would partly seal the cracks in the granite.

3 Seaward dipping or offshore sediments which are impervious, such as shales, mudstones, clays, etc. The disposal site should be located below the level at which the groundwater enters the sea. The access to the disposal site could be via a shaft on land connected to an undersea tunnel from the base of the shat.

4 Impervious basement rocks under a sediment cover. Since most of the groundwater movement would take place in the sedimentary rocks, there would be very little chance of the groundwater coming into contact with the underlying basement rocks.

Some radioactive wastes are mixed with concrete, packed into steel containers and embedded in concrete. Concrete provides a highly alkaline environment ($pH > 9$), which dramatically reduces the solubility of radionuclides (in some cases, by a factor of about 10,000). Besides, the corroding metal creates a low Eh environment which reduces the solubility and increases the sorption of some long-lived radionuclides (Attewell, 1993, p. 199).

Before isolating the wastes in deep, stable geological formations, the radioactive wastes are sometimes solidified, granulated and encapsulated in borosilicate glass or SYNROC (synthetic analogue of natural silicate rock, in which the radionuclides occupy positions in the lattice structures). These materials are highly radioactive, but are evidently more convenient to handle than (say) the nitric acid solutions of radioactive nuclides.

The geological environment suitable for the isolation of high level radioactive wastes, has to satisfy a number of requirements: the rocks should be thick, with low permeabilities, with structures which do not allow the movement of groundwater, low susceptibility for being altered by radiation, and good ion-exchange capacity to absorb elements. Among the various possible geological materials, salt, clay shale and granite, have been considered most suitable. The good points of salt are its very low permeability and water content, total lack of porosity, ability to seal any fractures, and high thermal conductivity (which helps to dissipate the radiogenic heat). The disadvantage is that it is easily dissolved by water in adjacent formations. Besides, salt is an economic mineral in its own right, and could serve as a useful repository for various materials, including hydrocarbons. Clay shale is highly impervious, has high ion-exchange capacity, and occurs in the form of relatively homogeneous formations of large thickness. However, clay shales are plastic, and have a high water content, part of which may be mobilized when the rock is subjected to stresses. Granite is highly rigid, has low porosity and permeability and large thicknesses. But joints are common in granites, and water could flow through these joints. However, the jointing becomes less pronounced at great depths (say, of more than 3000 m). Among the three rock types mentioned above, several countries favour granites (e.g. Fennoscandian granites of Olkiluoto, Finland, and Fősmark, Sweden). Bentonite which is highly impervious, has emerged as a good candidate for sealing the repository from contact with groundwater.

The configuration of the repository would depend upon the nature and quantity of the waste to be stored, heat likely to be emitted and the rate at which it could be dissipated, the geotechnical properties of the rocks and the way they are likely to react to thermal and mechanical stresses, etc. If the repository is proposed to be sited in an inhabited area, the perceptions and objections of the communities cannot be ignored (NIMBY – Not in my back yard). Various possible scenarios are modeled taking into account all the scientific, geotechnical and socioeconomic considerations.

Apart from Gobi Desert (China), there are excellent sites in parts of central Africa which admirably satisfy all the criteria for siting the nuclear waste repositories (uninhabited, very low rainfall, stable cratonic regions of hard rocks, etc.). Considering that just the preparatory investigations for the Yucca Mountain (USA) site cost USD 7 billion, it would make sound economic sense for these countries to allow the location of the nuclear waste depositories in their territories in return (say) for a 500 MWe nuclear power station. But the waste disposal is a highly emotive issue in Africa as the African countries have been duped by some unscrupulous western companies into accepting hazardous wastes without adequate protection.

3.4.2 High-level wastes immobilized in glass

The following account draws extensively from the account of Grambow (2006).

The liquid effluents that result from the reprocessing of the spent nuclear fuel are highly radioactive. It is generally accepted that the most practical way to manage these effluents is to immobilize them in glass and dispose them in a geologic repository several hundred metres below the ground. In order to prevent the radionuclides from reaching the biosphere for hundreds of thousands of years through contact with groundwater, the glass-filled waste form canisters are further protected through engineered barriers, favourable geochemical conditions, and retention of radionuclides on mineral surfaces and slow rates of groundwater movement.

Borosilicate glasses can be produced on industrial scale. Their advantages include the ability to accommodate a wide variety of waste stream compositions, ease of industrial processing, and stability against radiation, thermal and chemical perturbations.

The radioactive wastes that need to be immobilized in glass include several nuclear fission and activation products, minor actinides (Am, Np, Cm) generated by neutron capture reactions, and minor amounts of U (<0.15%) and Pu (<0,12%) that were not recovered during reprocessing. Long-term isolation is needed for the radionuclides such as, (^{129}I, ^{135}Cs, ^{99}Tc, ^{126}Sn, ^{79}Se, ^{237}Np, ^{239}Pu, and ^{241}Am) which have long half-lives. Also, it has to be kept in mind that radionuclides (such as, ^{137}Cs/^{137m}Ba, and ^{241}Am) generate radiogenic heat for hundreds to thousands of years.

Vast volumes (230,000 m^3, with activity of 1.3×10^7 TBq of activity) of High Level Wastes (HLW) are proposed to be vitrified at Hanford, Washington, USA, at an estimated cost of USD 11 billion. Vitrification is planned to commence in 2019.

Important nuclear waste glass production facilities are listed in Table 3.4.1.

3.4.3 Geochemical considerations in the fabrication of waste glass

The fabrication of waste glass involves the binding together of radioactive elements with non-radioactive glass-forming elements, such as, Si, B and alkali elements.

The quantity of radioanuclides that could be immobilized in glass depend upon their valences (6, 7 or 8) and concentrations (from a few percent to about 20% in the case of uranyl ions). In the glass network, the actinides, Pu, Np and Th, are held in 6–8

Table 3.4.1 Nuclear waste glass production facilities.

Vitrification plant	*Location*	*Total waste glass produced (in tonnes)*	*Number of canisters*	*TBq**
DWPF, Savannah River site	Aiken, South Carolina, USA	3,600	2,000	–
West valley	New York, USA	–	300	–
BNFL	Sellafield, U.K.	900	2,280	1×10^7
AREAVA NC	La Hague, France	4,000	10,000	1.5×10^8
Pamela	Mol, Belgium	500	2,200	2.4×10^5
Total vitrification facility	Japan		62	

Source: Grambow, 2006.

TBq = Tera-Bequerel = 10^{12} atoms decaying per second.

coordination, the large, heavy rare earth elements and actinides, Am and Cm, are 8-fold coordination, and hexavalent actinides (e.g. U) are held in 7–8 fold coordination. A few nuclides, such as, ^{129}I, are not amenable for incorporation. Platinoids (i.e. Pd, Ru, Rh) which are insoluble in the glass matrix, occur in the glass as micrometer-sized metallic or oxide inclusions. When the glass cools, it may undergo fracturing, leading to considerable enlargement of external surface area.

The design of a glass waste is customized by choosing the non-radioactive glass-forming additives to suit the viscosity-temperature relations, behaviour of radionuclide volatiles at high processing temperatures, electrical conductivity and chemical durability of the waste components (Grambow, 2006). The French Commisariat à l'Ènergie Atomique (CEA) and Areva NC have developed the cold crucible melter (CCM) technology which allows increasing load of corrosive waste constituents such as, sulphate, molybdate and phosphate, and refractory elements, such as, Zr, Al, and Si. The melter has been so designed as to allow the direct feeding of solids (calcine + glass frit), liquid wastes and glass-forming additives. Figure 3.4.1 (source: AREVA NC) depicts the French two-stage continuous vitrification process.

3.4.4 Long-term stability of nuclear waste glass

Though thermodynamically, glass is a metastable solid, it is stable over long periods. For instance, volcanic glasses have persisted in natural environments over periods of millions of years, without getting devitrified to crystalline phases. In the temperature range expected in the case of interim storage, transport and disposal of the glass canisters (center-line temperatures, <450°C; outer surface temperatures <200°C), the probability of devitrification of the waste glass is very low.

Another source of information to assess the stability of the waste glass is the rate of diffusion of radionuclides in glass. For instance, the solid-state tracer diffusion coefficient of Sr and Cs in borosilicate glass extrapolated to the disposal temperatures (<100°C), are about 10^{-35} m^2/s (100 million years = 3.156×10^{15} s). The tracer diffusion coefficient of Na$^+$ in borosilicate glass is 10^{-14} m^2/s, whereas the diffusivities of

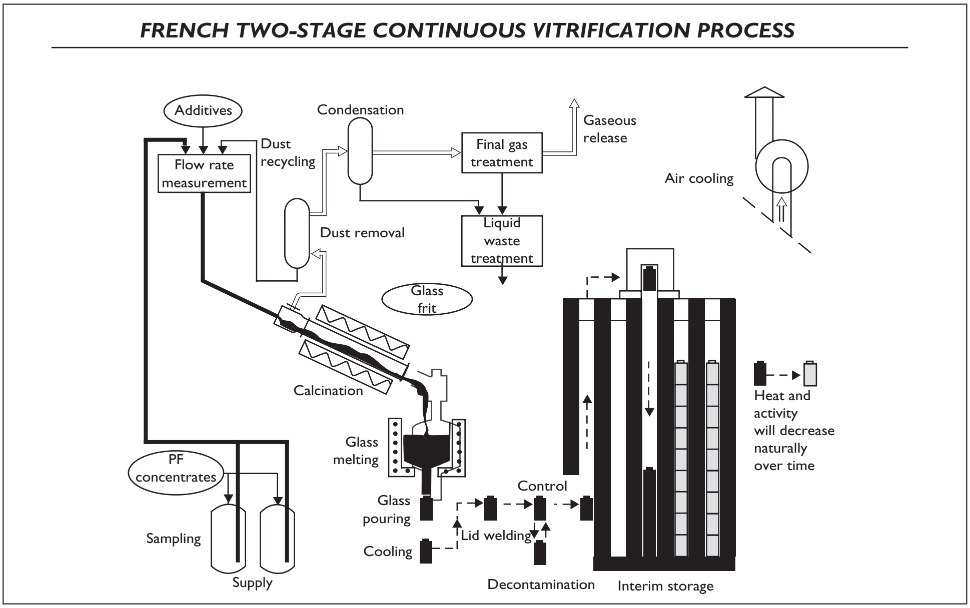

Figure 3.4.1 French two-stage vitrification process.

Source: AREVA NC.

Rb, Cs and Sr are <10^{-18} m^2/s. So the waste glass can be expected to be stable for long periods. It has been found that cast-iron overpacks can protect the waste glass from coming into contact with groundwater, and thereby ensure the isolation of the waste glass for many thousands of years. The overpack is an innovative idea, as short-lived fission products, such as Cs and Sr, generate considerable amounts of heat during the first few hundred years after disposal.

3.4.5 Glass – water reactions

Kinetic and geochemical modeling indicates that it would take hundreds of thousands of years for glass to be completely corroded by migrating groundwater at normal temperatures. When glass interacts with water, alkali ions at the surface get selectively removed. Then water diffuses into the glass structure and H^+ ions replace alkali ions.

As a result of this process, silica-like hydrated glass surface with a thickness of a few tens of nanometers, come into existence. "The alkali and alkaline earth ions (e.g. ^{135}Cs, ^{137}Cs, ^{90}Sr) and boron are lost from the outer surface and from the hydrated subsurface region of the glass" (Grambow, 2006).

Nuclear waste glasses are more similar to basaltic glasses than obsidian glasses, both in terms of composition and environmental alteration patterns. The rate of alteration of basaltic glasses beneath the sediment cover, i.e. under silica-saturated conditions, is about one-thousand times less than at the sediment surface, i.e. under silica-undersaturated conditions. This is so because the affinity for the dissolution of glass is low in silica-rich sediment pore waters.

Radiation may decompose the water (radiolysis) but this process may be counteracted by the generation of hydrogen due to corrosion of the metal container.

For glass to have a long (>200,000 years) life time, the solution adjacent to glass need to be saturated in silica. Hence any chemical reaction that consumes dissolved silica would reduce the life time of the glass. When the container corrosion products, such as siderite or magnetite, absorb silica, the corrosion of glass increases. Radionuclide release rates from glass in a simulated repository of clay formation, are as follows: Am: 10^{-14}/y; Pu: 10^{-10}/y; Cs and I: 5×10^{-6}/y. Cs and I are potentially mobile, and there are therefore uncertainties in regard to their glass dissolution, and safety assessment. Actinides and Tc have very low solubilities under reducing geochemical conditions and are strongly retained on clay minerals. European studies on the performance of repositories of clay formations, indicate that the actinides, Pu, Am and Np, will most likely decay in the vicinity of glass, without ever migrating to the biosphere.

It has been found that the matrix dissolution rates as observed in the laboratory are different from those found as observed in the field. Fortunately, the laboratory-observed rates are higher than the field- observed rates. Under the circumstances, though the long-term performance of the nuclear waste glasses may not be accurately predictable, the laboratory-observed data may be safely used as boundary conditions.

3.4.6 Modeling of alteration mechanisms

In order to assess the long-term performance of the nuclear waste glasses when placed in geological repositories, geochemical codes can be made use of to model alteration mechanisms in respect of natural analogues of nuclear waste glasses (Allison et al., 1991). The purpose of these codes are summarized as follows (Shrivastava, Bajpai and Rani (2008):

KINDIS – To simulate irreversible dissolution of minerals and reversible precipitation of secondary phases, speciation of the aqueous species.

PHREEQC – Capabilities for speciation and saturation index calculation;
Calculates batch reaction;
Calculates inverse modeling which finds set of mineral and gas mole transfer;
Simulate kinetic reactions.

MINTEQA2 – Calculates complex chemical equilibrium;
Solve the set of mass-action and mass-balance expression.

REACT – Manipulates chemical reactions;
Calculates stability diagrams and the equilibrium states of natural waters.
Traces reaction processes;
Models reactive transport in one and two dimensions and plots the results

EQ3/6 – Calculates the distribution of the aqueous species;
Models aqueous geochemical system.
Computes reaction paths; Allows creating or evaluation models.

3.4.7 Immobilization of waste actinides in ceramic

The following account is drawn from the excellent overview of Lumpkin (2006).

A ceramic to be used for immobilizing radioactive wastes needs to have the following attributes: (i) low susceptibility for dissolution and low elemental release rates if and when exposed to groundwater in the geological repository, (ii) flexibility in accommodating different kinds of wastes in its structure, (iii) potential for high waste loading, (iv) processing and cost efficiency, and (v) ability to withstand radiation damage (if the mineral becomes amorphous due to radiation damage, its physical properties and proneness to dissolution would be adversely affected).

Synroc or polyphase ceramics for partially reprocessed spent fuel have pyrochlore as the main actinide host (Table 3.4.2). The performance potential of individual waste form phases for actinides is given in Table 3.4.3.

Two decades ago, Ringwood et al. (1988) came up with the innovative idea of using "synroc", a synthetic rock made up of stable titanate minerals, for the safe disposal of nuclear wastes, ranging from the reprocessed spent fuels from commercial power reactors to high-grade plutonium derived from decommissioned nuclear weapons. Polyphase and special purpose crystalline ceramics can be tailor-made to suit the requirements of particular wastes. When placed in geological repository, crystalline waste forms are less subject to aqueous dissolution and are hence more chemically durable than borosilicate

Table 3.4.2 Waste form and waste loading.

Waste form	*Main phases*	*Application/waste loading*
Synroc-C	Zirconolite, perovskite, Hollandite, rutile	High Level Wastes (HLW) from reprocessing upto 20 wt%.
Synroc-D	Zirconolite, perovskite, Spinel, nepheline	US Defense wastes, 60–70%
Synroc-F	Pyrochlore, perovskite, uraninite	Conversion of spent fuel, Approximately 50 wt%
Tailored ceramics	Magnetoplumbite, zirconolite, spinel, uraninite, nepheline	US Defense wastes, to 60% or higher
Pyrochlore	Pyrochlore, zirconolite-4M, brannerite, rutile	Separated actinides or Pu, upto about 35 wt.%.
Zirconolite	Zirconolite, rutile	Separated actinides, upto about 25 wt%
Monazite	Monazite	Actinide-lanthanide wastes, to about 25 wt% actinides
Zircon	Zircon	Pu-rich wastes from dismantled nuclear weapons
Glass-ceramics	Titanite, zirconolite, pyrochlore, perovskite, nepheline, sodalite, alumino-silicate glass	Canadian wastes (low actinide content), complex legacy wastes, intermediate level wastes
Others	Britholite, kosnarite, murataite, crichtonite	Proposed as host phases for actinides and lanthanides

Source: Lumpkin, 2006.

Table 3.4.3 Performance characteristics of individual phases.

	Aqueous durability	*Chemical flexibility*	*Waste loading*	*Radiation tolerance*	*Volume swelling*	*Natural analogues*
Perovskite (Ca, Sr) TiO_3	Low	Medium	Low	Medium	High	Yes
Pyrochlore $Gd_2(Ti, Hf)_2O_7$	High	High	High	Low-high	Medium	Yes
Zirconolite $CaZrTi_2O_7$	High	High	Medium	Low-medium	Medium	Yes
Zircon $ZrSiO_4$	High	Medium	Low (?)	Low	High	Yes
Monazite $LnPO_4$	High	Medium	High	High	Low	Yes
Zirconates $Gd_2(Zr, Hf)_2O_7$	High	Medium	Medium	High	Low	No
Zirconia $(Zr, In, Act)O_{2\text{-}X}$	High	Medium	Medium	High	Low	No
Brannerite UTi_2O_6	Medium	Medium	High	Low	?	Yes
Crichtonite $Ca(Ti, Fe, Cr, Mg)_{21}O_{38}$	?	High	Medium	Low (?)	?	Yes
Murataite $Zr(Ca, Mn)_2 (Fe, Al)_4 Ti_3O_{16}$	High	High	Medium	Medium	?	Rare
Garnet $Ca_3Zr_2(Al, Si, Fe)_3 O_{12}$	?	High	Medium	Low	?	Yes*
Titanite $CaTiSiO_3$	Medium	Medium	Low	Low	Medium	Yes
Minerals of the apatite group (e.g. britholite)	Medium	Medium	Low	Low	Medium	Yes
Kosnarite $NaZr_2(PO_4)_3$	Medium	Medium	Medium	Low	?	Yes

Source: Lumpkin, 2006.

* Natural garnets do not generally contain significant amounts of Th&U.

glass. But the catch in the case of the crystalline waste form is that the alpha decay of the actinides immobilized in it could render the crystalline material amorphous, and thereby lead to volume expansion, lattice breakdown and reduced chemical durability.

Monazite, pyrochlore, zircon and zirconolite resist aqueous dissolution at low temperatures. Though perovskite ($CaTiO_3$) is a titanate, it is not considered suitable for immobilization of wastes, as it is susceptible to chemical dissolution and alteration to anatase. Zirconolite is suitable as a host matrix for smaller lanthanide ions and tetravalent actinides. Large lanthanide ions (e.g. Nd, Ce) and trivalent actinides prefer to occupy the large Ca site in perovskite. The chemical durability and mechanical properties of the glass-ceramic waste forms are affected by the partitioning, as actinides are strongly partitioned into crystals rather than into glass matrix.

The dissolution rates (10^{-4} g/m^2/d) of the actinides (Np, Pu, Am, Cm) in the short-term tests (less than 60 days) are much lower than more soluble elements. Pu controls the dissolution behaviour of the actinides, except under most acidic conditions.

When synroc samples (both Na-free and Na-rich) are doped with ^{244}Cm, the radiation dose rate (1.3×10^{15} α/mg) reduces the density of Na-free samples. Na-rich samples develop cracks and undergo density change when exposed to dose of 8.5×10^4 α/mg.

3.4.8 Single phase waste forms

High-level Wastes (HLW) can be separated into various fractions (e.g. actinides, and short-lived radionuclides, such as, Sr and Cs). Thus, Pu is immobilized in pyrochlore-based ceramics. In these ceramics, pyrochlore is often intermixed with zirconolite (as layered intergrowths), perovskite and brannerite. It is a common practice to add TiO_2 as excess component to facilitate processing.

3.4.8.1 Pyrochlore

The general formula of pyrochlore is $A_2B_2X_6Y$, in which A and B are 8- and 6-coordinated cation sites, and × and Y are 4-coordinated anion sites. Generally, A = Na, Ca, Y, lanthanides and actinides; B = Ti, Zr, Nb, Hf, Ta, Sn, and W. The end-member is taken to be $Ca\,U\,Ti_2\,O_7$. In this compound, actinides substitute for U, Hf which is a neutron absorber, substitutes for Ti on the B site, Gd substitutes for Ca and U at the A site.

Natural pyrochlores with Nb, Ta, Ti and minor Sn and Zr at B site undergo amorphization at a critical dose rate of 10^{16} α/mg. This dose is 2–3 times higher than for $CaPuTi_2O_7$. Long-term annealing of amorphisation apparently takes place due to atomic diffusion. That actinide-rich, radiation-damaged and compositionally zoned crystals in natural pyrochlore of Adamello massif, northern Italy, have co-existed for forty million years, without cracking or significant loss of U and Th, is indicative of the long-term performance of the Pu-immobilized pyrochlore waste form (Lumpkin, 2001). The incorporation of Zr at the B site in the pyrochlore structure, appears to impart radiation "resistance" or "tolerance" to the pyrochlore structure, in that the radiation damage is annealed quickly in a matter of picoseconds. The more the structural transformation of pyrochlore to fluorite-like geometry, the greater the radiation resistance of pyrochlore (Lumpkin, 2006).

3.4.8.2 Zirconolite

The end-member composition of 2M polytype is $CaZrTi_2O_7$. Ca and Zr sites may be occupied by actinide and lanthanide elements with appropriate charge balancing adjustments, leading to other polytypes, such as 3T, 3O, 4M. There is thus a high level of chemical flexibility in the composition of the mineral. Doping by ^{238}Pu or ^{244}Cm, or irradiation by heavy ions, renders zirconolite amorphous. Both natural and synthetic zirconolites are highly resistant to chemical corrosion, and this holds good even to amorphous samples of zirconolites with high accumulated doses.

3.4.8.3 Perovskite

Perovskite (Ca, Sr, TiO_3) has an ABX_3 structure. In the nuclear waste form, cations of Na, Ca, Sr, lanthanides and minor actinides occupy large A site cations, and Ti and minor Al occupy octahedral B-site cations. Perovskite requires an amorphization dose 2–5 times higher than pyrochlore and zirconolite. It is, however, susceptible to dissolution, and gets converted to anatase (TiO_2) and other secondary alteration products. When perovskite interacts with aqueous fluids, amorphous Ti-O-H films form at temperatures below 100°C, or crystalline TiO_2 forms at higher temperatures. Because of its proneness for dissolution, perovskite is not considered suitable as a host phase for actinides or radioactive Sr in waste form, to be lodged in a geological repository.

3.4.8.4 Brannerite

In the brannerite (UTi_2O_6) structure, layers of Ti octahedra are connected to columns of U octahedral. Upto 20% of U and 15% of Pu may be loaded on to brannerite. When Ca, REE, Th and other elements are incorporated at the A site, the charge is balanced by the oxidation of U^{4+} to U^{5+} or U^{6+}. The irradiation by the alpha decay of uranium contained in brannerite, renders the mineral metamict or amorphous. Consequently, brannerites older than 10 million years, are invariably amorphous (The author had a personal experience in this regard. When the author visited the Elliot Lake (Canada) brannerite deposit, the resident chemical engineer told him that he was mystified as to why the ore could be dissolved by lesser quantity of acid than expected. The author told him that brannerite became metamict (amorphous) because of internal radiation damage, and hence needed less acid for decomposition than would be needed by fully crystalline mineral). Altered natural brannerite loses U, whose concentration may decrease to about 1 wt.% of UO_2, in heavily altered places.

3.4.8.5 Zircon

Zircon (Zr SiO_4) ideally contains 67.2% ZrO_2. There is a strong geochemical coherence between Zr and Hf, because of the similarity in ionic radius and charge (Zr^{4+}: 0.84 Å; Hf^{4+}: 0.83 Å). Hence hafnium is invariably present along with Zr, with Hf/Zr ratio of 0.02. Zircon gets concentrated in late stage silicic magmas, and hence occurs as an accessory mineral in granites. Because of its hardness, high specific gravity (6.4) and its ability to withstand corrasion and corrosion, zircon survives as a detrital mineral in placers. Upto 5000 ppm or less of other impurities, such as, Ca, lanthanides and actinides may occupy Zr site, and P may occupy the Si site. The critical dose for amorphisation is 4×10^{15} α/mg. The total volume of zircon may swell upto 18%.

As the alpha-decay dose increases from 6×10^{13} α/mg to more than 1×10^{16} α/mg, the dissolution rate increases from 2×10^{-4} g/m^2/d to 2×10^{-2} g/m^2/d. This spans the crystalline-amorphous transition (Ewing et al., 1982).

3.4.8.6 Monazite

ABO_4 stoichiometry. (Ce, La) PO_4; with Th upto 12%; U_3O_8: 0.1–10%. It is an accessory in granites and several metamorphic rocks. Present in granite pegmatites.

Most common in placers. It consists of chains of alternating BO_4 tetrahedra and AO_9 polyhedra. The monoclinic monazite structure does not permit open tunnels, and is approximately 10% denser than zircon structure. Monazite resists metamictization despite being exposed to high alpha-decay arising from its high radioactive content (upto 27 wt% of $UO_2 + ThO_2$). Also, monazite is highly resistant to dissolution, with irradiated, fully amorphous synthetic monazite being as resistant as crystalline zircon.

3.4.8.7 Conclusion

Investigations are in progress to evaluate the potential of a number of other minerals, such as, britholite, crichtonite, garnet, kosnarite and murataite and sphene, for immobilizing waste forms, such as, actinides, lanthanides, radioactive Sr and I.

Among the individual phases (Table 3.4.3), perovskite is most prone to dissolution. Magnetoplumbite structure type is an alternate host for perovskite for radioactive Sr. Pyrochlore and zirconolite are the preferred actinide host phases. The strongest point in favour of crystalline zircon is its high resistance to dissolution. However, its usefulness as a waste host is compromised because of its tendency to undergo large volume swelling, and anisotropic expansion of unit cell and greater proneness for dissolution, as a consequence of metamictization. Monazite resists metamictization much better than zircon, brannerite, pyrochlore and zirconolite. Also, its dissolution rate is low. However, the ability of monazite to accept substitutions is much less than that of pyrochlore and zirconolite which allow a large range of substitutions.

Ability to withstand radiation damage has emerged as an important consideration in the choice of hosts for wastes. Chemical durability, crystal chemical flexibility, processing temperature and availability of natural analogues, are taken into consideration while making choice of phases for waste loading.

3.5 RADIATION HAZARDS

3.5.1 Radiation from rocks

Steinnes (1990) summarized the information regarding the natural ionizing radiation. The ionizing radiation to which man is exposed is derived from two sources: (1) External, arising from cosmic rays, and from primordial nuclides present in the earth's crust, and (2) internal, arising from naturally occurring nuclides taken into the human body through food and water.

The ambient radiation dose (vide radiation units described in 3.1.1) can be estimated from the concentrations of uranium, thorium and potassium, in rocks and soils, by using the empirical conversion factors given by Adams & Lowder (1964, p. 1031), namely, that the radiation dose of 1 $\mu R\ h^{-1}$ is caused by 0.58% of potassium, or 1.32 ppm of ^{238}U or 2.78 ppm of ^{228}Th in equilibrium.

Table 3.5.1 gives the estimated radiation levels (in $\mu R\ h^{-1}$) in various rocks, on the basis of their U, Th and K contents (Aswathanarayana, 1995, p. 154).

The per capita Annual Effective Dose equivalent (in μ Sv) from irradiation sources in the areas of normal background, as estimated by UNSCEAR (United Nations

Scientific Committee on the Effects of Atomic Radiation) in 1982, is given in Table 3.5.2. It may be noted from the Table, the internal sources of radiation (1340 μSv) is roughly double that from external sources (650 μSv).

It may be noted that out of the total radiation dose of 2 mSv y^{-1}, uranium series alone account for about half of the natural dose. In terms of radiation dose, 2 mSv y^{-1} is equivalent to two X-ray chart examinations. The exhalation of ^{222}Rn gas (daughter of 226 Ra) has been estimated to be in the range of 0.05 to 10 mSv y^{-1}. The average human dose from rainwater has been put at 5 mSv y^{-1}.

The natural background radiation dose in normal areas is 0.1 μGy h^{-1}. However, in areas of radioactive thermal springs, radioactive ore-bearing areas, radioactive soils, etc., the external dose may be a few hundred times higher, say 20–30 μGy h^{-1}. People living in the monazite-bearing beach areas along the southwest coast of India, are exposed to an annual average external dose rate of 3.8 mGy y^{-1} (about five times that in normal background areas), without any significant ill effects.

Table 3.5.1 Natural radiation levels in rocks.

Rock type	*U (ppm)*	*Th (ppm)*	*K (ppm)*	*Radiation levels (in μR h^{-1})*
Low-Ca granite	3.0	17.0	42,000	15.6
High-Ca granite	3.0	8.5	25,200	9.7
Syenite	3.0	13.0	48,000	15.2
Basalts	1.0	4.0	8,300	3.6
Ultramafics	0.001	0.004	40	<0.01
Shale	3.7	12.0	26,600	11.7
Sandstone	0.45	1.7	10,700	2.8
Carbonates	2.2	1.7	2,700	2.8
Deep-sea clays	1.3	7	25,000	7.8
Pelagic carbonates	0.1	1	2,900	1.6

Table 3.5.2 Internal and external sources of radiation (in μSv).

Source	*External source*	*Internal source*	*Total*
Cosmic rays	300		300
Cosmogenic radionuclides		15	15
Primordial radionuclides			
^{40}K	120	180	300
^{87}Rb		6	6
^{238}U to ^{234}U		10	10
^{230}Th		7	7
^{226}Ra		7	7
^{222}Rn to ^{214}Po		800	800
^{210}Pb to ^{210}Po		130	130
^{238}U series	*90*	*954*	*1,044*
^{232}Th		3	3
^{226}Ra to ^{224}Ra		13	13
^{220}Rn to ^{208}Tl		170	170
^{232}Th series	*140*	*186*	*326*
Total (rounded)	650	1,340	2,000

Natural radioactive substances are assimilated by man in the following ways; (1) Inhalation of ^{222}Rn and ^{220}Rn from air, (2) adventitious inhalation of radioactive dust with ambient radiation dosage levels of more than 1 mR h^{-1}, (3) ingestion of food and water (water containing more than 200 pCi l^{-1} of radioactive substances is harmful), (4) ^{210}Pb and ^{210}Po deposited on plant surfaces by the decay of ^{222}Rn, and ingested by animals, whose flesh is eaten by man. It has been estimated that the average intake of radioactive substances in USA is 2 pCi d^{-1} per capita.

3.5.2 Radon risk

In some countries, the Indoor Air Quality (IAQ) has been seriously impaired by the presence of radon. Since the end risk in this instance happens to be cancer, however low its probability is, there is much public concern about the radon problem, particularly in Industrialized countries. Lao (1990) gave a detailed account of the measurement, mitigation and prevention of indoor radon.

^{222}Rn is the gaseous daughter of ^{226}Ra. One ppm of uranium corresponds to 12.3 Bq kg^{-1} of ^{226}Ra, and could result in the radon concentration of soil gas of the order of 4000 Bq m^{-3} (gross estimate). The following alpha-emitters are among the progeny of ^{222}Rn.

A radioactive aerosol develops when some of the radon progeny attach themselves to other particles in indoor air. When a person inhales such radioactive air, the radon progeny would be deposited in the person's respiratory tract. Alpha particles irradiate epithelial cells, and cause lung cancer. There is epidemiological evidence linking the lung cancer of the uranium miners with the inhalation of radon in the mines. The risk of lung cancer is enhanced if the person concerned is a smoker.

In response to pressure differences between the inside of the house and the surrounding soil, radon-bearing soil gas infiltrates into dwellings through pores in concrete slabs and construction joints. A secondary source could be the radon-contaminated drinking water. Thus, the radon entry is determined by the concentration of radium in the soil, the permeability of the soil, and the tightness of the foundation. A moist clay is virtually impermeable, whereas the foundation of coarse, dry, crushed rock or gravel, is highly permeable. The higher the radium content of the soil, and the greater the permeability of the soil and the foundations, the higher is the radon content of the indoor air. Energy-efficient houses with low ventilation have higher indoor radon levels.

It has been estimated that about 2% of the houses in USA have indoor radiation levels of 8 pCi l^{-1}, with associated life-time risk of lung cancer of 2%. In Sweden, about

Table 3.5.3 Progeny of ^{222}Radon.

Isotope	*Half-life*	*Energy of the alpha particle (in MeV)*
^{218}Po	3.05 min.	6.0
^{214}Bi	19.7 min.	5.5
^{214}Po	160 µsec	7.7
^{210}Po	128 days	5.3

2% of the homes have radon progeny levels greater than 400 Bq m^{-3}, which could cause 400–800 cases of lung cancer in a population of 8 million (Akerblom, 1987).

Some countries have prescribed norms for indoor progeny levels for new dwellings: 5 mSv y^{-1} in UK, 0.02 WL in USA, and 100 Bq m^{-3} in Sweden. Remedial action is recommended when the radon progeny in the existing dwellings exceeds a designated level (for instance, 20 mSv y^{-1} in U.K., and 400 Bq m^{-3} in Sweden). The Swedish Board of Urban Planning and Building recommended various measures to take care of the radon risk (Table 3.5.4, after Akerblom, 1987).

The contribution of soil gas to indoor radon concentration (C_m) could be estimated from the following equation:

$$C_m = \frac{C_t L}{(n + \lambda)V}$$

where C_t = radon concentration in soil gas; L = flow rate of soil gas into the house, n = ventilation in the indoor area; V = volume of the indoor area; λ = decay constant of ^{222}Rn (0.00755 h^{-1}).

Radon risk maps are compiled on the scale of 1:50,000 on the basis of bed-rock geology and radioactivity (as measured by a 256-channel, airborne gamma-ray scintillation spectrometer with large crystal volume). These maps are useful to local authorities, planners and builders to decide where and how to build radon-safe houses. Portable gamma-ray spectrometers are used for on-site inspection where the radon level is more than 15 μR h^{-1}. In the case of the existing houses, commercial services are available in several countries for the assessment of indoor radon progeny level, and for ameliorative measures to be taken if the level exceeds the safe norm.

Lahermo (1990) depicted the natural radiation environment in Finland (Fig. 3.5.1) in the form of distribution of uranium in soils (A), uranium in water drilled in the bedrock (C) and ambient indoor air (in 6149 dwellings in 235 localities) (D). As should be expected, there is a strong similarity in the areal distribution patterns in respect of uranium in groundwater, uranium in till soils, and the total exposure rate of natural radiation measured at the ground surface, and radon indoor air.

Table 3.5.4 Building code in relation to radon risk.

Classification of risk	*Type of ground*	*Building code*
High risk	Uranium-rich rocks like granites and pegmatites, carbonaceous and phosphatic shales. Highly permeable soils, gravel or coarse sand. Radon concentration in soil gas >50,000 Bq m^{-3}	Radon-safe construction, thicker, reinforced concrete or ventilation below the foundation
Normal risk	Rocks and soils with normal uranium content. Radon in soil gas, 10,000 to <50,000 Bq m^{-3}	Radon prospective construction; no open holes in the foundation
Low risk	Rocks with low uranium content, such as, limestones, sandstones and basic rocks; soils with low permeability, such as clays and silts; radon content in soil gas <10,000 Bq m^{-3}	None

It has been estimated that 10 to 30% of the lung cancer cases in Norway are attributable to radon (quoted by Steinnes, 1990).

3.5.3 Biogeochemical cycling of radioactive pollutants

The biogeochemical cycling of radioactive pollutants through the atmosphere, hydrosphere and pedosphere follow the same chemical pathways as their chemical analogues.

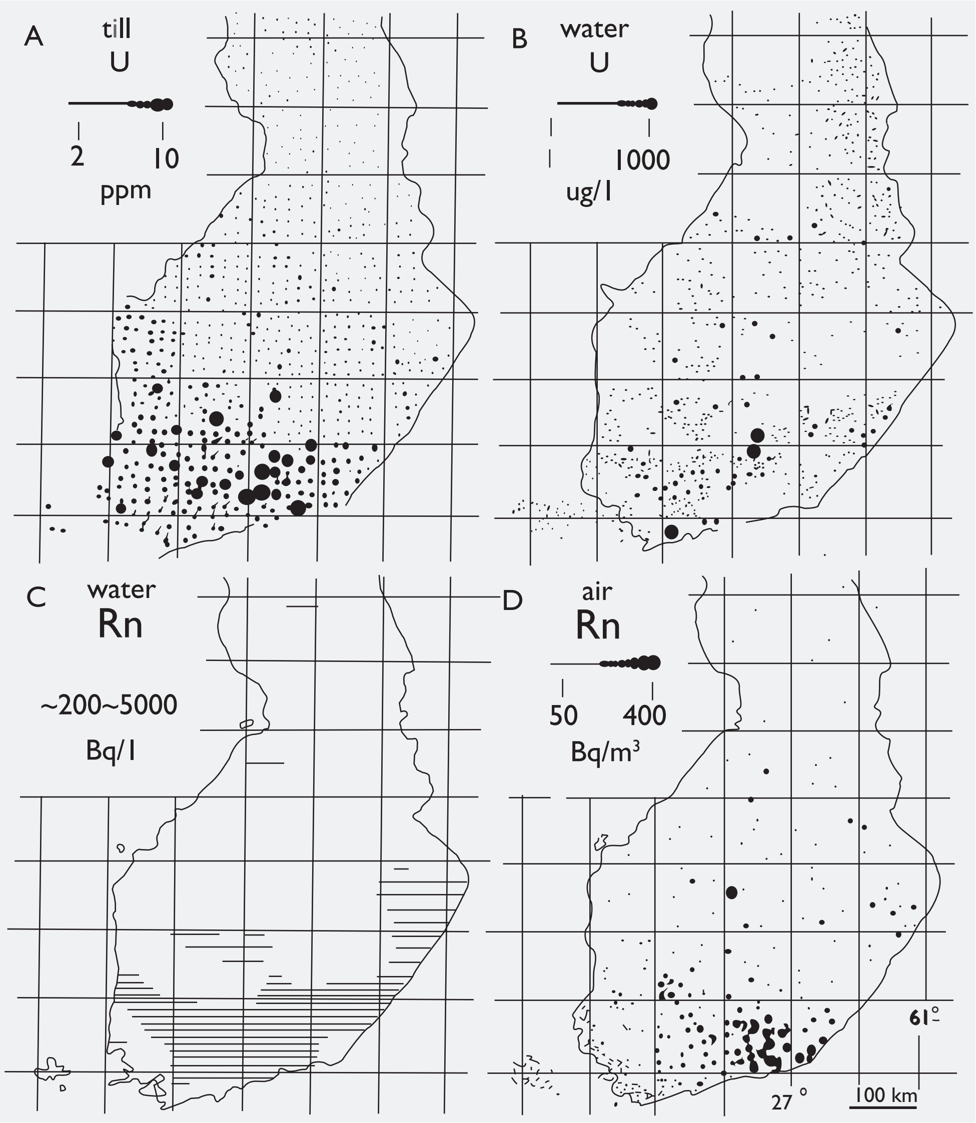

Figure 3.5.1 Natural Radiation Environment in Finland.

Source: Lahermo, 1990.

3.5.3.1 Atmosphere

The atmospheric contamination of radioactive pollutants caused by man arises from nuclear weapons testing, nuclear power plants operation, and serious nuclear accidents like Chernobyl. The radioactive nuclides released to the atmosphere due to weapons testing are listed in Table 3.5.5.

The mixing time in the atmosphere is about two years. Noble gases like ^{85}Kr with half-lives of more than 2 years, are distributed more or less homogeneously, unlike aerosol-bound nuclides whose distribution generally tends to be inhomogeneous. Due to chimney effect, the fission products arising from the Chernobyl accident rose to heights of 1000 to 1500 m, from where they got transported to long distances.

3.5.3.2 Hydrosphere

Nuclides arising from anthropogenic activities, such as, ^{95}Zr, ^{95}Nb, ^{106}Ru, ^{137}Cs, ^{141}Ce, and ^{144}Ce, are input into waters of the lakes and sea due to precipitation. Fission product nuclides in seawater are present in different forms: ^{89}Sr and ^{137}Cs are in solution, ^{95}Zr, ^{95}Nb, ^{144}Ce, and ^{147}Pm, are precipitated, and ^{90}Sr is partly in solution and partly precipitated. Groundwater is depleted in some isotopes because of absorption in the soil. For instance, ^{137}Cs is strongly retained in the soil, and very little of it goes into groundwater. In contrast, ^{90}Sr is not bound in the soil, and therefore is passed into groundwater. As groundwater is an important source of drinking water in many communities, the extent of infiltration of radioisotopes in the soil assumes great importance. ^{131}Iodine in the hydrosphere due to Chernobyl has reached the peak level of 1.1 kBq l^{-1} on May 3, 1986 (i.e. one week after the incident).

3.5.3.3 Pedosphere

The artificial radioactivity of the soils arises from sedimentation of the nuclides. The principal nuclides involved are: ^{137}Cs, ^{134}Cs, ^{131}I, and ^{90}Sr. The mobility of the nuclides in the soil profile depends upon the pH, Eh, texture (content of clay), porosity and permeability and organic matter content. The rate of movement ranges from a few

Table 3.5.5 Total radioactivity released through atomic weapons tests.

Nuclide	*Half-life (years)*	*Activity (Bq)*
^{3}H	12	1.1×10^{20}
^{85}Kr	11	4.8×10^{16}
^{90}Sr	28	7.8×10^{17}
^{106}Ru	1.0	1.6×10^{19}
^{129}I	1.6×10^{7}	4.4×10^{11}
^{135}Cs	2.0×10^{6}	1.7×10^{13}
^{137}Cs	30	1.2×10^{18}
^{239}Pu	2.4×10^{4}	
^{240}Pu	6.6×10^{3}	1.5×10^{7}

mm to several cm per year. In the case of agricultural soils, the kind of tillage employed is of critical importance.

3.5.3.4 Biosphere

Biosphere includes the food chain which is critically important in the health of man. In the aquatic environment, microorganisms like plankton filter the radionuclides from seawater. When fish eat the plankton, the radionuclides enter the fish. It has been found that some fish have a few thousand times more radiocaesium than the waters in which they live. The degree of enrichment depends upon the competing trace elements. For instance, the ^{90}Sr activity of the fish increases with the decreasing Ca concentration of the water in which they live. In general, isotopic concentrations are higher in freshwater fish than in the salt water fish. In the case of land plants, some radionuclides are picked up by the plants from the precipitation via the stomata (e.g. ^{95}Zr, ^{103}Ru, ^{106}Ru, ^{140}Ba, ^{140}La, ^{144}Ce, ^{144}Pr), as well as the soil via their roots. The physiology of the plant and the geochemical environment of the soil would determine which plant would take up which nuclides and in what proportion. For instance, ^{91}Y, ^{95}Zr, ^{106}Ru, ^{127}Te, ^{141}Ce, and ^{239}Pu (which are mostly hydrolysate elements) tend to accumulate in the roots, whereas ^{90}Sr and ^{137}Cs end up in the above ground parts. Thus, the kind of radionuclides that we should look for in (say) potatoes, may be different from those that we should look for in (say) tomatoes.

3.5.3.5 Transfer between pools

Like other elements, radionuclides move from one compartment to another, through biogeochemical cycles involving soil-air-biota. The fall-out from nuclear weapon tests in the atmosphere during 1950–62 has been estimated by Jacubick to be 500 kCi of ^{239}Pu, with a particulate range 0.01 to 100 μm. The nuclear plants release ^{239}Pu into the atmosphere after processing it through high efficiency particulate filters. ^{239}Pu in the atmosphere moves through soil, water and plants to man, and hence its movement needs to be closely monitored.

The movement of ^{137}Cs and ^{90}Sr from soil to plant is a case in point. The soil-plant transfer factors for Cs and Sr are given in Table 3.5.6 (quoted by Becker-Heidmann and Scharpenseel, 1990).

3.5.4 Meltdown

A meltdown occurs when the fuel assemblies in a reactor are heated beyond their melting point (the term, meltdown, has come into colloquial usage, to indicate the total collapse of an institution or a company or a system). This can happen because of any of the following situations: (1) when the pressure of the confined coolant falls below specification without means to restore it, (2) Physical loss of coolant (which may be deionized water, heavy water, inert gas, or liquid sodium), (3) Uncontrolled power excursion, when a sudden power spike in the reactor occurs, due to a sudden increase in the reactor reactivity, (4) Structural or coal-based fires. A meltdown may destroy the containment structure partly or wholly, thereby releasing the core's highly radioactive and toxic elements into the atmosphere and the environment.

Table 3.5.6 Soil – plant transfer factors for Cs and Sr*

	Cs	*Sr*
Leafy vegetable	0.075–0.9	0.08–7.8
Potatoes	0.023–0.16	0.015–0.38
Root vegetables	0.0025–0.15	0.55–21
Grass	0.0011–14	0.018–9.8
Clover	0.004–33	0.22–7.4
Vegetation	0.05	0.4

* Ratio of Bq kg^{-1} of fresh plant material to Bq kg^{-1} of dry soil.

Though nuclear meltdowns have occurred in nuclear submarines and nuclear reactors in several countries, two nuclear accidents stand out, namely, The Three-Mile Island accident and Chernobyl accident.

3.5.4.1 *The Three-Mile Island (TML) accident*

The TML accident began on Mar. 28, 1979 (Wednesday) in Dauphin County, near Harrisburg, Pennsylvania, USA, when TMI-2, one of the two pressurized water reactors, suffered a partial meltdown. The accident resulted in the release of 43 kCi of radioactive krypton (1.59 PBq) and less than 10 Ci (740 GBq) of ^{131}iodine. About 25,000 people who lived within 8 km. radius of TMI, were alerted.

Though no one was killed or injured because of the TMI accident, the consequences of the accident were catastrophic for the nuclear power industry in USA. The popular feeling against nuclear power was so intense that there was virtual cessation of reactor construction for decades.

3.5.5 Chernobyl reactor accident

On April 26, 1986 (Saturday), there was an explosion in one of the four, graphite-moderated, water-cooled nuclear reactors at Chernobyl, 128 km from Kiev in Ukraine (former Soviet Union). Chernobyl is on the banks of the Pripyat River which flows into the Dnieper. The region is relatively flat with gentle slopes. It is the most serious nuclear accident in the world to date, and gave a foretaste of the horrors of nuclear war. Basically, Chernobyl was the result of steam explosion. Fuel heated up very rapidly, and this caused all the coolant water to vaporize instantly, causing an explosion. Some fuel did melt, but that does not account for the magnitude of the disaster.

About 50 MCi (million curies) or 2×10^{18} Bq of radioactive fission products and noble gases (including ^{123} Xenon) which correspond to about 5% of the total fission products inventory of the reactor core, escaped. About half of this amount relates to radionuclides which figure in the food chain. Radioactivity got released in two distinct plumes – one on the first day (12 MCi), and another on the seventh day. Containment was effected by the eleventh day, and the emissions ceased after that. Meteorological conditions determined the pattern of dispersion of the Chernobyl radioactive cloud.

The details of the accident, and its consequences have been reviewed by IAEA (1986) and Sagersthal (1991).

The radionuclides involved in the release, and their radioactivity are given in Table 3.5.7.

The Chernobyl radioactive plume rose to a height of 3 km before it started spreading horizontally. About 50% of the emission of condensable products fell in an area of about 60 km radius around the accident site. The rest of the emissions fell in an area of 10 million km^2 in Europe. The fallout was controlled by rainfall, other things being equal.

The maximum values of deposition (in terms of kBq m^{-2}) of total caesium (^{137}Cs + ^{134}Cs) and ^{131}I, in various countries following the Chernobyl accident, is given in Table 3.5.8.

It may be noted that the meteorological conditions rather than the distance from the site of the accident, determined the extent of fallout. This explains as to why Sweden received >50 times more deposition than the neighbouring Denmark.

People were exposed to Chernobyl radiation in four ways: (1) Exposure to external radiation from the radioactive isotopes in the cloud as it passed overhead, (2) Exposure to internal radiation from inhaled radioactive isotopes, (3) Exposure to external radiation from the radioactive material deposited on the ground during the transit of the cloud, and (4) Exposure to radiation from radioactive isotopes ingested in food (Barnaby, 1986). The radioactive isotopes in the Chernobyl cloud which are of the greatest importance to human health are the isotopes of iodine and caesium (Table 3.5.7) which got widely deposited in Europe.

3.5.5.1 ^{131}Iodine and Caesium isotopes

About 7.3 MCi of ^{131} I was released during the accident. ^{131}I has a half-life of 8 days. It gets concentrated in the milk of the cows when they ingest contaminated grass. When people drink the milk of such cows, ^{131}I gets concentrated in the thyroid, and could cause thyroid cancer. Two isotopes of caesium are involved. ^{134}Cs with a half-life of 2.05 years, and ^{137}Cs with a half-life if 30 years. About 0.5 MCi of ^{134}Cs and 1.0 MCi of ^{137}Cs were released in the accident. Caesium ingested by animals from the vegeta-

Table 3.5.7 Radionuclides released and their radioactivity.

Radionuclide	*Half-life*	*Emitted radiation*	*Radioactive release (Bq)*
^{89}Sr	53 d	$\beta + \gamma$	8.0×10^{16}
^{90}Sr	28 d	β	8.0×10^{15}
^{103}Ru	40 d	$\beta + \gamma$	1.2×10^{17}
^{106}Ru	1 y	β	6.0×10^{16}
^{131}I	8 d	$\beta + \gamma$	2.6×10^{17}
^{134}Cs	2 y	γ	1.9×10^{17}
^{137}Cs	30 y	$\beta + \gamma$	3.8×10^{16}
^{141}Ce	32 d	$\beta + \gamma$	1.0×10^{17}
^{144}Ce	284 d	$\beta + \gamma$	1.0×10^{17}
^{239}Np	2.4 d	$\beta + \gamma$	4.2×10^{15}
^{239}Pu, etc.	13 y +	α	5.0×10^{15}

Table 3.5.8 Maximum values of deposition (in kBq m^{-2}) of Cs and I in various countries.

Country	*Total Caesium*	*^{131}Iodine*
Sweden	190	950
Norway	>100	Not given
Italy	100	~500
F.R.G.	65	160
Austria	60	700
Switzerland	41	180
Finland	~30	190
Greece	28	60
Ireland	22	16
U.K.	20	40
Netherlands	~9	26
France	7.6	Not given
Luxembourg	7.3	~40
Denmark	4.6	4.2
Belgium	3.0	10
Turkey	0.9	8.0
Japan	0.41	3.8
Iceland	0.10	Small
Canada	0.065	0.24
Spain	0.041	0.09
Portugal	0.012	0.013
USA	Small	>1.9

tion ends up in meat. Vegetables, fruits and dairy products are also contaminated by radioactive caesium. It has been reported that when bentonite clay is included in the feed of the sheep, their meat remained uncontaminated, possibly because radioactive caesium got bound by bentonite and excreted.

Korobova et al. (1998) studied the mobility of ^{137}Cs and ^{90}Sr in soils, and their transfer in the soil-plant system in the Novozybbkov District affected by the Chernobyl accident. They found a sharp contrast in the behaviour of ^{137}Cs which is strongly fixed in the soil (to the extent of 40–93%),whereas 70–90% of ^{90}Sr is present in water-soluble, exchangeable, and weak-acid-soluble forms. Vertical migration of radionuclides, which is detected to a depth of 30–40 cm, is most pronounced in local depressions with organic and gley soils. In woodlands, most of the ^{137}Cs is fixed in the plant litter and upper mineral soil layer. In the case of floodplain grasslands, radionuclides are associated with soils having fine texture. The uptake of radionuclides by plants decreases in the following order: legumes > herbs > grasses. A high accumulation of ^{137}Cs in potato tubers grown in sandy, podzolic soils, has been noted. Korobova et al. (1998) recommend that people living in the areas within the zone of contamination exceeding 15 Ci km^{-2}, should avoid eating local forest products, and cattle should not be allowed to graze on wet floodplain meadows.

The Chernobyl fall-out contaminated milk and meat products all over Europe. Extensive surveillance networks were set up to monitor the radioactivity of fresh milk, lamb meat, etc. For instance, the Government of U.K. prescribed the following Derived Emergency Reference Levels (DERL's) for milk: 2,000 Bq l^{-1} for ^{131}I, 2,000 Bq l^{-1} for ^{137}Cs, and 3,100 Bq l^{-1} for ^{134}Cs, totaling 7,100 Bq l^{-1} of milk. Some countries have adopted more stringent measures: any food-stuff with >1000 Bq l^{-1} of radioactivity was declared unacceptable for human consumption.

It has been estimated that about 75 million people in erstwhile USSR have been exposed to Chernobyl radiation, with the "average" individual receiving about 33 mSv (millisieverts) or 33 REM over his life time. The range for the EEC countries was about 8 mSv. There was, however, considerable variation in the radiation exposure among the European countries, depending upon the pattern of movement of Chernobyl cloud. For instance, the average effective dose in Italy was eight times more than that in the UK. This is so because about half of the total radiation was received by the Italians, about a quarter by the Greeks, and about 20% by West Germans, among the EEC countries. Poland and Austria were exposed to dosages closer to 8 mSv.

The claims of deaths of tens of thousands of people in the Chernobyl accident are highly exaggerated. One estimate puts the number of fatalities as 210. According to Chernobyl Forum (2006), 28 emergency workers died due to exposure to very high radiation dose, 15 patients died from thyroid cancer, and there may be 4,000 cancer deaths from among 600,000 people who received high dose of radiation. It has been estimated that there might be 10–15 million cancer death in the affected population in the erstwhile Soviet Union during the next 70 years. Estimates of the total number of cancers producible in Europe (excluding erstwhile Soviet Union) due to Chernobyl accident vary from 4,600 to 76,000. This large range in the estimate arises from the fact that the projected number of cancer deaths attributable to 1,000 man-Sv has been estimated by various authorities to have a range of 24 to 360. The carcinogenic effects of exposure to large doses of radiation are poorly known for the simple reason that, barring the survivors of Hiroshima and Nagasaki, there is no large group of people exposed to such high radiation doses.

The Chernobyl accident had serious effects on biota as well. For instance, it led to enhanced concentrations of radionuclides in the air above Sweden, which were then washed into lakes and streams in Sweden. Petersen et al. (1986) reported that as of August, 1986, increased radioactivity was found at all trophic levels of the fresh water ecosystem, from algae to top carnivore. Aquatic biota was exposed to 250–1,000 Bq l^{-1} of caesium isotopes, i.e. 25 times higher than normal and was still rising.

3.5.5.2 Current concerns in regard to Chernobyl

The following account is drawn from the Report of the Chernobyl Forum (2006).

"*Chernobyl's Legacy: Health, Environmental and Socioeconomic Impacts*".

Chernobyl accident has been a traumatic experience for humanity as a whole. It generated a strong wave of antipathy against nuclear power itself.

Consequent on the break-up of the Soviet Union, three countries, Ukraine, Russia and Belarus, are concerned with the problems of Chernobyl. They have already spent hundreds of billions of dollars, but there is no end in sight for the suffering of the people.

About 1000 emergency workers and personnel that were on-site during the first days of the accident, received the highest doses of radiation. Though some 600,000 people have been involved in the containment, cleaning and recovery operations subsequent to the accident, they were not exposed to dangerous levels of radiation. At present, more than 5 million people live in the area "contaminated" by radioactive materials from Chernobyl.

About 100,000 people living in the contaminated area still receive a higher dose of radiation than is permissible.

Thousands of persons who were children or adolescents at the time of occurrence of the Chernobyl accident, have developed thyroid cancer as a result of exposure to radioactive iodine. Fortunately, most of them recovered after medical treatment. There has been increase in the number of cases of certain types of leukaemia and solid cancers, and possibly cardiovascular diseases. Investigations are ongoing to quantify such cases.

There is no convincing evidence of adverse effects on human fertility, heritable diseases and the overall health of the children of the exposed parents, in the case of the people who received relatively low doses of radiation.

During the last 22 years since the accident, most of the short-lived nuclides (vide Table 3.5.7) that were released by the damaged reactor, have since been transformed into stable, non-radioactive material. However, long-lived radionuclides, such as ^{137}Cs (half-life: 30 yrs.) will continue to remain radioactive. Similarly, contamination of crops, meat and milk by short-lived radionuclides has ceased, but contamination by longer-lived ^{137}Cs is of concern in some rural areas. Also, forest produce, such are berries, mushrooms and game (such as, reindeer meat in Scandinavia) which contain high concentrations of ^{137}Cs, may continue to be contaminated for some decades to come. Most of the water bodies and fish are now free of radioactive contamination, except for a few closed lakes. Genetic anomalies, increase in mortality and decrease in reproduction in some plants and animals living within 30 km of the site, continue to be reported. Over the years, as the radiation levels decrease, biological populations are recovering.

After the accident took place, a structure was built to contain the damaged reactor. This structure left much to be desired, as it was built hurriedly and under extremely difficult conditions as the construction workers were facing dangerous levels of radiation. The structure deteriorated badly during the last two decades. A new containment structure is being built, and the damaged reactor is being dismantled.

People living in the affected areas continue to be worried about their health and economic future. None of the three affected countries have the financial means to provide payments to all the affected people. The Chernobyl Forum (2006) categories the affected people into three groups, assistance to whom is customized to their needs:

Category 1: About 100,000 to 200,000 people who are worst affected, and who are in dire need of assistance because of their poor health and poverty. Bulk of the state assistance should go to these people.

Category 2: Help to normalize the lives of several hundreds of thousands of people whose lives have been significantly affected by the accident, but who have already been able to support themselves.

Category 3: Provision of good health care, social services and employment to several million people who have been only mildly affected by the accident.

3.5.6 Epilogue

There is much public concern about the safety of nuclear reactors. But the facts speak for themselves. During the 12,700 reactor-years of civil nuclear power generation, there has been only two nuclear accidents: Three Mile Island accident in USA in 1979, in which no body was killed, and the Chernobyl accident in 1986, which killed about 40 people directly, and had serious health and environmental consequences. It is important to remember that the Chernobyl accident did not bring to light any previously unknown phenomena or safety issue. The Chernobyl reactor design was basically flawed – it would not have taken place if the already known reactor physics has been taken into consideration in the design.

Since then, the nuclear industry developed elaborate safety methods. The Energy Related Severe Accident Database (ENSAD) maintained by Switzerland contains data on about 18,000 accidents from 1969 onwards, of which 35% are energy-related. A comparison of the frequency-consequences for full energy chains in the OECD countries in terms of fatalities per GW/y (source: IEA, 2008, p. 295) show that the nuclear power is the safest of all. Since the plot covers only OECD countries, it does not take into account Chernobyl accident, since Russia is a non-OECD country. If latent deaths as a consequence of air pollution are taken into account, the fossil fuel sources come out badly risk-wise.

3.6 FUTURE OF NUCLEAR POWER

Countries all over the world are increasingly looking for nuclear power to solve their energy problems. Generating electricity from nuclear power is becoming competitive vis-à-vis coal and gas generation. Besides, there are advantages in terms of reducing carbon emissions, and security of supply. The emphasis now is on improving the safety and efficiency of nuclear power reactors.

3.6.1 Resource position

Australia, Canada, Kazakhstan and South Africa have large resources of uranium, followed by Russia, Brazil, Namibia, Niger, Ukraine, China and Uzbekistan.

OECD (2005) has given the following prediction of the world nuclear generating capacity, in GWe: 2005 – 373; 2010 – 390; 2015 – 427; 2020 – 455; 2025 – 491, and prediction of uranium demand (in tonnes of uranium): 2005 – 66,800; 2010 –72,000; 2015 – 79,000; 2020 – 80,900.

The information given in Tables 3.6.1, 3.6.2 and 3.6.3 has been drawn from the Red Book of 2007.

An MIT study projects that the nuclear power will grow from 350 GWe today to 1500 GWe in 50 years (Ansolabehere et al., 2003). This would need 10 Mt of uranium. The total of all resources known (~23 Mt) is twice the amount of uranium projected to be needed. A number of areas in the world have not been adequately explored. Considering the large variety of geologic settings in which uranium could occur, and taking into account the economic value of ore elements that might be co-extracted with uranium, the known resources of uranium listed in the Red Book

Table 3.6.1 Proposed production methods to exploit inferred resources.

	<USD 40/kg	*<USD 80/kg*	*<USD 130/kg*
Open-pit mining	202,100	199,300	251,900
Underground mining	296,700	692,400	767,000
In situ leaching	344,400	378,200	359,700
Heap leaching	12,700	22,300	23,900
In place leaching	1,500	24,800	24,800
Co-product/by-product	367,000	445,800	493,200
Unspecified mining method	10,200	95,600	180,100
Total	1,203,600	1,858,400	2,130,600

Table 3.6.2 Reasonably assured resources (t) by deposit type (totaling 7,702,700 U t).

	<USD 40/kg	*<USD 80/kg*	*<USD 130/kg*
Unconformity-related	424,100	485,200	491,600
Sandstone	347,800	537,000	999,500
Hematite-breccia complex	492,300	492,300	449,400
Quartz-pebble conglomerate	88,100	126,400	163,600
Vein	0	80,600	156,800
Intrusive	47,400	131,480	183,700
Volcanic and caldera-related	50,400	135,700	157,800
Metasomatite	121,200	291,300	304,900
Other*	162,300	221,000	284,300
Unspecified	32,800	67,800	96,700
Total	1,766,400	2,598,000	3,338,300

* Includes surficial, collapse breccia, phosphorite, etc.

Table 3.6.3 Inferred resources (t) by deposit type (totaling 5,102,600 U t).

	<USD 40/kg	*<USD 80/kg*	*<USD 130/kg*
Unconformity-related	148,300	152,300	158,100
Sandstone	374,800	468,100	524,400
Hematite-breccia complex	393,900	399,900	401,500
Quartz-pebble conglomerate	113,700	132,000	138,300
Vein	0	108,500	167,700
Intrusive	61,600	78,800	104,200
Volcanic and caldera-related	1,000	44,600	53,500
Metasomatite	14,800	289,200	368,800
Other*	77,800	133,900	154,400
Unspecified	17,700	51,100	59,700
Total	1,203,600	1,858,400	2,130,600

* Includes surficial, collapse breccia, phosphorite, etc.

are conservative. It can be safely said that the uranium resources are available for a few hundred years.

A 1000 MWe of nuclear power will displace 15–25% of the predicted growth of carbon emissions.

The cost of uranium was \$27.74/kg in 2004, and \$31.59/kg in 2005. Though the fuel costs of nuclear power (\$0.018/kWh) are not much different from those of thermal power (\$0.023–0.05/kWh), the capital costs of building a new nuclear plant (\$2000/kWe) are much higher than for a modern gas turbine plant, which could be built as cheaply as \$500/kWe (source: Macfarlane and Miller, 2007).

Nuclear power plants face problems of getting a license, political opposition to plant siting, and concern about health effects, and contamination of water resources and the Environment.

Presently, the cost of the nuclear fuel in India is roughly twice that of the global price. The price will go down when India is able to access the international uranium market through the Nuclear Suppliers Group (NSG). In the Indian context, nuclear power is likely to become competitive with thermal power at places 500 km away from coal deposits. In the case of coal-fired power stations, the fuel cost accounts for about 60% of the electricity cost, as against 15% in the case of Light Water Reactors. Consequently, nuclear power costs will increase at a lower rate than for coal power, as a consequence of inflation.

Australia, Canada, India, Kazakhstan, Russia, USA and Uzbekistan concentrated on exploration of unconformity-type, sandstone-type and haematite-breccia type uranium occurrences in 2004. Hardly any exploration work for uranium was done elsewhere in the world during the past 15 years. But as the price of uranium is picking up because of increased interest in nuclear power, exploration and mining of uranium is likely to be taken up in several countries in the future.

In Aug. 2007, there were 438 operating nuclear plants in 30 countries, with a total capacity of 372 GW. Thirtyone reactors which are under construction have a capacity of 24 GW. Nuclear power accounted for 2700 TWh in 2006, which corresponds to 16% of the global electricity production. The world has experience of 12,000 reactor-years. USA, France and Japan account for about 60% of the world's nuclear power. In 2006, France has the highest share (78%) of nuclear power in the world. Figure 3.6.1 (source: IEA, 2008, p. 285) gives the nuclear share of electricity generation by country in 2006. The current demand for uranium is 67,000 tonnes per year.

3.6.2 Cost of nuclear power

The direct costs of nuclear power have three components: construction costs, operation, maintenance (O&M) and fuel costs, and backend costs (towards waste management and decommissioning costs). To compare different technologies, a "levelized" cost per kWh or MWh is computed. The construction costs vary from country to country, depending upon the length and complexity of the preconstruction period, capital costs (excluding interest), construction time and the cost of capital. The capital cost may vary depending upon whether it is turnkey project, or a project built directly by the organization. The construction time depends upon the management efficiency and availability of high-quality components. For instance, Japan could build an 800 MW

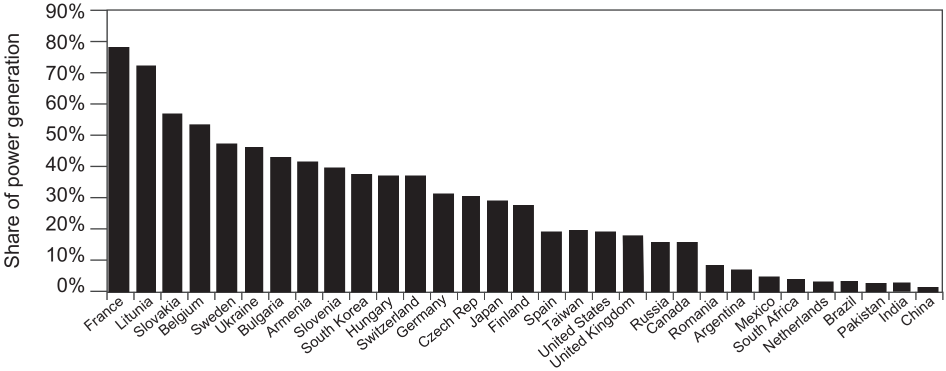

Figure 3.6.1 Nuclear share of electricity generation by country, 2006.

Source: IEA, 2008, p. 285.

BWR in 41 months, whereas Finland took 72 months for the purpose. The cost of the capital which has a major impact on the construction costs, depends upon the financing scheme – for instance, the discount rate is higher for nuclear power plants than for fossil power plants, as the investors and stakeholders see nuclear power as a high risk venture.

The operating (O&M and fuel) costs vary greatly between the countries, depending upon the labour costs, plant size and age, inspection and insurance costs, etc. Though the spot prices of uranium went up significantly, relatively small quantities are traded in this manner. In 2003, nuclear production costs in USA were US cents 1.72/kWh. Finland and Sweden have reported production costs of EUR 0.01/kWh. In the case of France which has 58 reactors, the O&M and fuel costs are EUR 0.014/kWh.

Decommissioning and majority of waste management costs are incurred at the end of the life of a reactor. Economists say that these costs do not significantly affect the levelized costs.

Some countries have achieved very high energy-availability factors in the existing plants. Consequently, while the generating capacity during 2003–2005 went up by only 1%, the nuclear electricity production went up by 2–3% (Figure 3.6.2), thus bringing about cost reduction.

The cost of nuclear power in new nuclear power plants are given in Table 3.6.4 (source: IEA, 2008, p. 290).

For future nuclear power stations, the levelized costs are expected to be in the range of USD 30–50/MWh. The levelized cost is higher than this range in the case of Japan (USD 69/MWh), because of high labour costs. Also, the levelized costs for coal, gas and nuclear power are very similar in Japan, possibly because Japan imports all fuels.

In some countries (e.g. Canada, Czech Republic, and France), nuclear power is cheaper than coal power and gas power by a margin of 10%. As fossil fuels have become costlier since 2004, this makes nuclear power more cost-competitive. The cost position in the case of nuclear power becomes even more attractive when the absence of carbon emissions is taken into account in cost calculations.

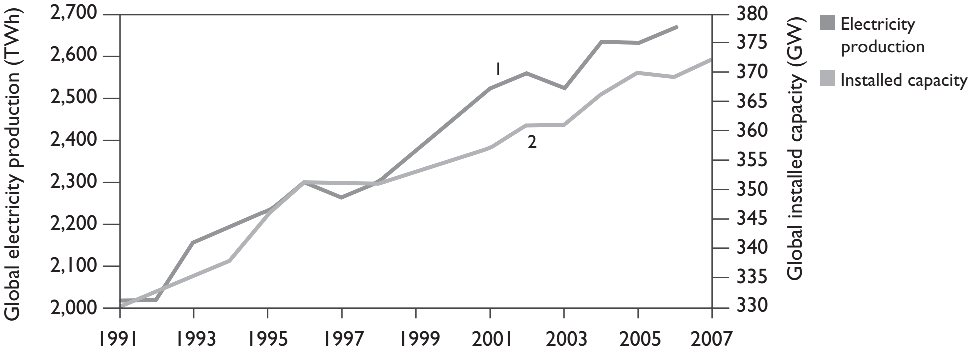

Figure 3.6.2 Historic trend of nuclear capacity and electricity production.

Source: IEA, 2008, p. 289.

Table 3.6.4 Results of recent studies on the costs of nuclear power.

Study	*Cost of capital (%)*	*Overnight cost kW*	*Levelized cost per MWh*
Massachusetts Institute of Technology (MIT, 2003)	11.5	USD 2000	USD 67
General Directorate for Energy and Raw Materials, France (DGEMP, 2004)	8	EUR 1280	EUR 28
Tarjanne & Luostarinen (2003)	5	EUR 1900	EUR 24
Royal Academy of Engineering (2004)	7.5	GBP 1150	GBP 23
University of Chicago (2004)	12.5	USD 1500	USD 51
Canadian Energy Research Institute (2004)	8	CAD 2347	CAD 53
Department of Trade and Industry, UK (DTI, 2007)	10	GBP 1250	GBP 38
IEA/NEA (2005)	10	USD 1089–3432	USD 30–50

Source: IEA, 2008, p. 290.

The Department of Trade and Industry (DTI) of UK came up with ranges of nuclear generating costs: High cost: USD 88/MWh; Central cost: USD 76/MWh; Low-cost: USD 62/MWh. The high-cost scenario is unlikely. The low-cost scenario is comparable to the estimates of the General Directorate for Energy and Raw materials (2004). DTI (May, 2007) made a sensitivity analysis of the key parameters that determine the cost of the nuclear power. The most important factors are the overnight cost and the cost of the capital. Other factors are: construction period, and O&M costs. Parameters such as Early load factor, operational lifetime, fuel cost, and waste disposal and decommissioning costs, have little impact on the levelized cost of nuclear power.

Nuclear power offers energy density and security of supply advantages. As the energy release from nuclear reaction per unit mass is about million times more than chemical combustion, it is easier to stockpile and transport uranium fuel, relative to fossil fuels. Also, countries, such as, Canada and Australia, which are politically stable, supply uranium. Disruption of fuel supplies is not expected to happen in the case of uranium supplies.

3.6.3 Projected nuclear power capacity

By 2020, the following countries have plans to increase their nuclear capacity (in terms of GW): China – 40, India – 16, Russia (22). Also, Japan – 9 GW by 2015, South Korea – 12 GW by 2017, Ukraine – 16 GW by 2030. Plans and proposals for new nuclear power reactors are given in Figure 3.6.3 (IEA, 2008, p. 299). France built 58 new nuclear reactors during 1977 and 1933 – an average of 3.6 reactors per year. As the world economic activity is about 30 times that of France, global construction of 100 new reactors (160 GW/y, if the reactors were to be EPRs – European Pressurised water reactors) is theoretically possible. There are however constraints, not only in skills, but also manufacturing constraints. For instance, there is only one company in the world, in Japan, which has the capacity to fabricate ultra-large forging for large reactor pressure vessels, and their books are full for the next three years. Similarly, heavy-lift cranes, large diesel generators for emergency core cooling, sulphur hexafluoride for switchgear, etc. are in short supply.

Highly skilled personnel are required not only to replace the retiring workforce, but also to build and maintain new generations of sophisticated reactors.

Most of the currently used reactors are large – typically 1000 to 1700 MW. Developing countries cannot afford such large, expensive reactors – they need small and medium reactors (SMRs). Also, it is not possible to connect remote areas in some countries (Siberia in Russia) to the national grid. India is developing 200 MW to

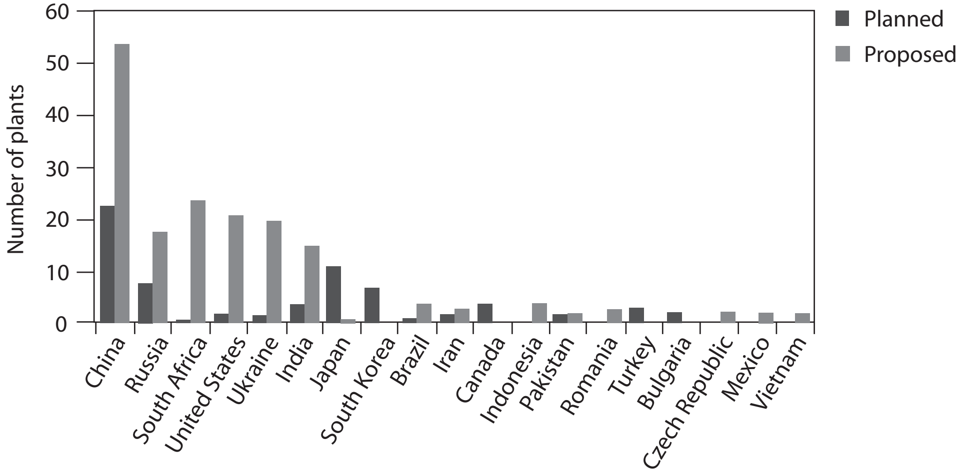

Figure 3.6.3 Plans and proposals for new power reactors.

Source: IEA, 2008, p. 299.

490 MW domestically produced reactors to provide electricity to communities to which national grid connection is uneconomical. SMR's are particularly suitable for non-electric applications that require proximity to the consumers, such as, desalinization plants (e.g. Tuticorin, India), and district-heating facilities (steam-generation for home heating in Russia) and production of hydrogen which promises to become a major transport fuel in future). Some SMR's would be factory-fuelled. This would not only bring down costs, but also prevent proliferation. Gas-cooled modular pebble-bed reactors serve the purpose of SMR's admirably.

3.6.4 Reactor designs

Nuclear reactors produce power by fission. They are classified on the basis of neutron energy (thermal or fast), coolant fluid (water, gas or liquid metal), moderator (light water, heavy water or graphite). Most (82%) of the nuclear power plants use ordinary water as moderator and coolant. Reactors used in Canada and India, use heavy water as moderator and coolant. UK has reactors cooled with carbon dioxide.

There are important lessons to be learnt from the Three Mile Island and Chernobyl accidents. Though the core of the Three Mile Island did melt almost completely, it stayed within the reactor vessel. The existence of the containment structure ensured that there was no release of radioactive gases. In the case of Chernobyl, by the time core melted, there was already a large steam explosion, graphite fires, and major release of contaminants, as Chernobyl did not have a containment structure. Now-a-days reactors are so designed as to make a meltdown highly unlikely, and to contain it should it occur.

Passively safe and inherently safe designs will make the meltdown highly unlikely, and the containment structure will ensure that the radioactive contaminants will not get released. Heavy water serves as both moderator and coolant in the CANDU reactors. The heavy water moderator tank (apart from the coolant system) and the light-water filled shield tank in the CANDU reactor serve as heat sinks, and prevent either the fuel meltdown or the breaching of the core vessel.

The longer the time lag between the start of the accident and the release of the radioactive contaminants into the air, the less dangerous would be the accident. This is because the most harmful isotopes in the fission product mixture are short lived. For instance, ^{131}I, who causes thyroid cancer, have a half-life of 8 d. If the release of radioiodine took place one week after its generation, as the criticality was terminated by SCRAM system (the immediate and full insertion of all control rods), the thyroid dose to the population would be much less than if the radioiodine got released one hour after it was generated.

Thus, in order to mitigate the consequences of the reactor accident, the plant operators should take into account three time factors: (i) Time required for the moderator and coolant water to boil: Prompt scramming will reduce the thermal power input and thereby delay the boiling of moderator and coolant water, (ii) Time required for the fuel to melt: This would depend upon the heat generated by the decay of fission products, heat capacity and the melting point of the fuel, (iii) Time required for the molten metal to breach the pressure vessel or its equivalent.

Fast breeder reactors have larger quantities of fissile material and higher neutron flux inside the reactor core. It is hence more difficult to control them, and therefore they are more susceptible to meltdown.

Failure of circuit integrity can cause accidental fires and lead to meltdown. This can be avoided by having two sets of electrical wiring. If one set of wiring fails, the standby set can be used to control the fires.

3.6.5 Pebble-bed reactors

The following account is drawn from Wikipedia and Internet sources.

Rudolf Schulten invented the pebble-bed reactor which is simple, safe and makes use of commoditized nuclear fuel. The pebbles are of the size of tennis balls (60 mm. hollow spheres of pyrolitic graphite which acts a the primary neutron moderator), with a mass of 210 g. A pebble contains 9 gm. of uranium (thorium or plutonium or enriched uranium and possibly MOX fuels could also be used). The nuclear fuels are in the form of ceramic (usually oxides or carbides). Thus, each pebble is effectively a "mini-reactor". When enough number of spheres is piled together in a bin, criticality is attained. A 120 MWe reactor needs 380,000 pebbles. The reactor design is such that it is inherently self-controlling. An inert gas, helium, nitrogen or carbon dioxide circulates through places between the fuel pebbles. The heated gas can run the turbine. If the heated gas has been rendered radioactive by the neutrons in the reactor, it may be made to pass through a heat exchanger where it heats another gas or generates steam. The exhaust from the turbine is hot enough for being used to warm buildings or chemical plants or even another heat engine.

In the case of conventional water-cooled, nuclear power plants, the cooling systems are complex, expensive and occupy much space because of the redundant backups. Because of the neutrons present in the reactor, the water and the impurities dissolved in it may become radioactive. Consequently, the high pressure piping on the primary side may become brittle, and needs to be regularly checked or even replaced. In contrast, inert gas like helium which serves as a coolant in the pebble bed reactor does not become radioactive because of neutrons. In the case of pebble-bed reactors, there is no piping as such (the spaces between pebbles serve as "piping"), and hence the problem of embrittlement of piping does not arise.

The pyrolitic graphite which is the main structural component of the pebbles sublimes at 4000°C. This is more than twice the design temperature of most reactors. Pyrolitic graphite slows neutrons very effectively, besides being strong and inexpensive. A pebble-bed reactor can therefore operate at a much higher temperature than the conventional light water reactors, without any problem. This permits the turbine to extract more mechanical energy from the same amount of thermal energy. This system uses less fuel per kWh, and is hence more energy efficient than the light water reactors.

Most pebble-bed reactors contain several (about seven) levels of containment. There are four containments right in the pebble itself – fission fuel in the form of a ceramic; high density, non-porous pyrolitic carbon; wrapping of silicon carbide; another wrapping of pyrolitic carbon. In addition, the reactor vessel is sealed, and the reactor is kept in a room with two-meter walls. The reactor system as a whole is enclosed in a containment building, which can withstand earthquake shocks and aircraft crashes.

Some pebble-bed designs are throttled by temperature – not control rods. This makes the design simpler, as no provision need be made for control rods.

Even if all the supporting machinery fails, a pebble-bed reactor will not melt or explode or release radioactive contaminants into the atmosphere and the environment.

The modular design of the pebble-bed design allows small reactors (100–200 MWe) to be mass-produced. This simplifies certification procedures, and installation practices. Such small reactors are needed for remote areas which cannot be economically connected to the national grid. Also, if one unit fails, another unit can be quickly substituted in its place, without waiting for repairs. Several pebble-bed reactors could be linked, if larger quantities of power (say, 1000 MWe) are needed.

Lastly, many experts believe that pebbled radioactive waste does not need immobilization – it can be directly disposed of in the geological storage.

3.6.6 R&D areas

Fourth generation reactor systems involve R&D in the following areas (International Energy Agency, 2008, p. 585):

i Development of sodium-cooled, fast reactors, gas or lead-cooled fast reactors, high temperature reactors, supercritical water reactors, molten salt reactors; accelerator-driven sub-critical systems,
ii Fuel cycles: Partitioning and Transmutation (P&T) and actinide recycling,
iii Materials to enhance safety,
iv Solutions to nuclear waste problems,
v Development of internationally approved safety standards and designs.

Generation V+ reactors

Designs which are theoretically possible, but which are not being actively considered or researched at present. Though such reactors could be built with current or near term technology, they trigger little interest for reasons of economics, practicality, or safety.

- Liquid Core reactor. A closed loop liquid core nuclear reactor where the fissile material is molten uranium cooled by a working gas pumped in through holes in the base of the containment vessel.
- Gas core reactor. A closed loop version of the nuclear lightbulb rocket, where the fissile material is gaseous uranium-hexafluoride contained in a fused silica vessel. A working gas (such as hydrogen) would flow around this vessel and absorb the UV light produced by the reaction. In theory, using UF_6 as a working fuel directly (rather than as a stage to one, as is done now) would mean lower processing costs, and very small reactors. In practice, running a reactor at such high power densities would probably produce unmanageable neutron flux.
- Gas core EM reactor. As in the Gas Core reactor, but with photovoltaic arrays converting the UV light directly to electricity.

Seven partners – European Union, China, India, Japan, Russia and USA–have joined together to build the International Thermonuclear Experimental Reactor (ITER) in Caderache in France. ITER will explore the techno-economic feasibility of fusion power. Fusion power is likely come into use only in the second half of the century.

3.7 ROLE OF NUCLEAR POWER IN INDIA'S ENERGY SECURITY

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3.7.1 Introduction

The world is experiencing a nuclear renaissance. Nuclear power is a compact, reliable and safe source of energy, needing little transport infrastructure. Most importantly, it helps in de-carbonizing the power sector. France, which obtains 80% of its electricity from nuclear power, has the lowest cost electricity and lowest per capita carbon emissions in Europe. Japan, which imports virtually all its energy needs, is giving preference to nuclear energy. USA and China which have extensive coal resources, are also going in for nuclear energy in a big way.

According to the study carried out by Department of Atomic Energy (DAE), Government of India, the present installed capacity of about 150 GWe (including captive power plants capacity) needs to be increased to 1300 GWe by 2050 in order for India to sustain the current economic growth rate of 8 to 9%.

3.7.2 India's energy resource base

Currently nuclear energy share at the primary level is about 1.5%, while in electricity generation, it is 3% (Table 3.7.1). The nuclear share in total primary energy mix is expected to grow, as the installed nuclear power capacity grows. Studies including the study by DAE have estimated the nuclear share to rise to between 4 to 8.5% by

Table 3.7.1 Energy resource base of India.

		Thermal Energy			*Electricity potential*
	Amount	*EJ*	*TWh*	*GW-yr*	*GWe-yr*
Fossil					
Coal	38 Bt	667	185,279	21,151	7,614
Hydrocarbon	12 Bt	511	141,946	16,204	5,833
Non-fossil					
Nuclear					
Uranium-metal	61,000 t				
In PHWR		28.9	7,992	913	328
In fast breeders		3,699	1,027,616	117,308	42,231
Thorium-metal	2,25,000 t				
In breeders		13,622	3,783,886	431,950	155,502
Renewable					
Hydro	150 GWe	6.0	1,679	192	69
Non-conv. ren	100 GWe	2.9	803	92	33

Source: A Strategy for growth of electrical energy in India – DAE, Government of India 2004; 1 GWe-Year = 8.76 Billion Units or 8.76 TWh.

2032 and 16.5% by 2052. The Integrated Energy Policy of India estimates share of nuclear power in the total primary energy mix to be between 4.0 to 6.4% in various scenarios in the year 2031–32. While the share is estimated to be 4% in the coal dominant scenario, it is 5.2% in the forced nuclear scenario and 6.4% in the forced nuclear + hydro + gas + clean coal + DSM + forced Nuclear + High Rail transport scenario. This has been arrived at using a multi-sectoral, multi period optimizing linear programming model. The optimization is carried out based on the least- cost solution (*source: Integrated Energy Policy, Planning Commission, Govt. of India*).

The study by the Department of Atomic Energy (DAE), estimates the nuclear share to be about 8.6% by the year 2032 and 16.6% by the year 2052 (*source: A Strategy for Growth of Electrical Energy in India, DAE, Govt. of India*).

The installed capacity of energy production in India is given in Table 3.7.2.

The share of nuclear power has been about 3% both in terms of installed capacity and generation. Thus the growth of nuclear power has been in tandem with the growth of electricity generation in India. Nuclear power contribution the country's electricity mix is expected to increase progressively in future with the implementation of the nuclear power programme.

3.7.2.1 Demand projections

Considering the present shortages, expected growth in demand and the need for a spinning reserve, the electricity demand projections have been made by several studies using different models. (*source: "A Strategy for Growth of Electrical Energy in India" DAE, Govt. of India*). The projections made in the Integrated Energy Policy are based on falling GDP-electricity elasticities. There has been a strong argument that the GDP-electricity elasticity will not fall in accordance with the past trends, as the fall due to sectoral shifts in the economy and increased efficiency of technologies will be offset by the increase in consumption as rising incomes will lead to energy intense lifestyles. However, considering the trends in India so far and in other countries, the

Table 3.7.2 Region-wise breakup of energy production (Installed capacity (MWe) – regionwise break up (as on 30.09.2007)).

			Thermal						
Sl. no.	*Region*	*Hydro*	*Coal*	*Gas*	*Diesel*	*Total*	*Nuclear*	*R.E.S*	*Total*
1	Northern	12,671	18,028	3,433	15	21,476	1,180	1,220	36,547
2	Western	7,004	23,503	5,861	17	29,381	1,840	2,670	40,895
3	Southern	10,646	15,973	3,586	939	20,498	1,100	5,899	38,144
4	Eastern	2,824	14,350	190	17	14,557	0	228	17,609
5	N. Eastern	1,116	330	772	143	1,244	0	146	2,506
6	Islands	0	0	0	70	70	0	11	81
7	Total	34,261	72,182	13,842	1,202	87,226	4,120	10,175	135,782

Source: Central Electricity Authority, Ministry of Power, Government of India.

In addition, a Captive Generating Capacity of 14,636 MW is available.

Renewable Energy Sources (RES) include Wind, Small Hydro Projects, Biomass Gas, Biomass Power, Urban & Industrial Waste Power.

Integrated Energy Policy has made the following projections for GDP-Electricity elasticity: Till 2012: 0.95; Till 2022: 0.85; Till 2032: 0.787.

The projections of electricity for 8% GDP growth rates are given in Table 3.7.3.

3.7.3 History of development of nuclear power in India

In contrast with the advanced countries where nuclear power came about as a spin-off of development of the strategic programme and related military research, in India, nuclear energy development began with the objectives of improving the quality of life of the people and self-reliance in meeting their energy needs. Dr. Homi J. Bhabha, the pioneer of atomic energy in India in a study on the needs and merits of taking up R&D in atomic energy in the country concluded that "Any substantial rise in the standard of living in this region–that can be sustained in the long term – will only be possible on the basis of very large imports of fuel or on the basis of atomic energy".

Self-reliance has been the hallmark of the Indian nuclear power programme. The adoption of the unique sequential three-stage programme and associated technologies was also based on the optimum utilization of the indigenous nuclear resource profile of modest Uranium (estimated to be 61,000 tons of Uranium metal) and abundant Thorium resources (estimated to be 225,000 tons of Thorium metal), the potential of which has already been given in the foregoing sections.

The sequential three-stage programme was based on a closed fuel cycle, where the spent fuel of one stage is reprocessed to produce fuel for the next stage. The closed fuel cycle thus multiplies manifold the energy potential of the fuel and greatly reduces the quantity of waste generated.

3.7.3.1 India's three-stage nuclear power programme

India's three-stage nuclear power programme is shown pictorially in Figure 3.7.1.

The first stage comprises of Pressurised Heavy Water Reactors (PHWR) fuelled by natural uranium. Natural uranium contains only 0.7% of Uranium^{235}, which undergoes fission to give energy. The remaining 99.3% comprises Uranium^{238}, which is not fissile. In the fission process, among other fission products, a small quantity of fissile Plutonium^{239} is formed by the transmutation of Uranium^{238}.

Table 3.7.3 Projections of electricity requirement to sustain 8% GDP Growth Rate.

Year	*Energy requirement (BUs)*	*Peak demand (GWe)*	*Installed capacity (GWe)*
2007	761	107	153
2012	1,097	158	220
2017	1,524	226	306
2022	2,118	323	425
2027	2,866	437	575
2032	3,880	532	778

Source: Integrated Energy Policy, Planning Commission, Government of India.

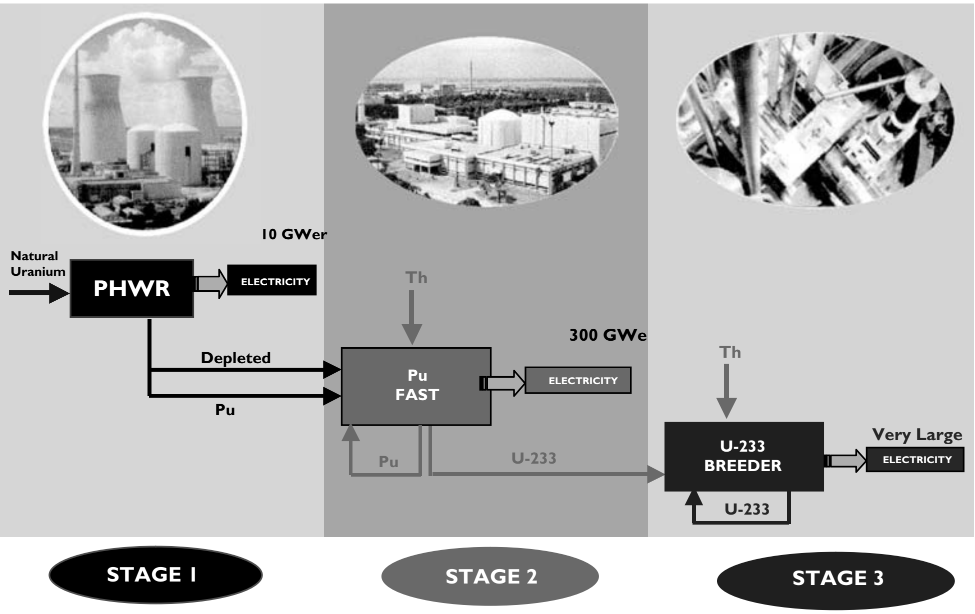


Figure 3.7.1 Three-stage nuclear power programme (See colour plate 13).

The spent fuel (spent of Uranium^{235}) is cooled for about five years to remove decay heat before reprocessing to recover Uranium^{238} and Plutonium^{239} and remove other fission products. The second stage, comprising of Fast Breeder Reactors (FBRs) are fuelled by mixed oxide of Uranium^{238} and Plutonium^{239} recovered by reprocessing of the first stage spent fuel. In FBRs, Plutonium^{239} undergoes fission producing energy, and at the same time, producing Plutonium^{239} by transmutation of Uranium^{238}. Thus the FBRs produce energy and fuel, hence termed Breeders. FBRs produce more fuel than they consume. Over a period of time, Plutonium inventory can be built by feeding Uranium^{238}.

Thorium^{232} is not fissile and has to be converted to Uranium^{233} by transmutation in a reactor for use as a fissile material. In the second stage, once sufficient inventory of Plutonium^{239} is built up, Thorium^{232} will be introduced as a blanket material to be converted to Uranium^{233}.

The third stage, using advanced thorium reactors will be breeders in a Thorium^{232}–Uranium^{233} fuel cycle. Direct use of Thorium^{232} as fuel will be in the third stage.

The three stage programme is observed to be robust and on course. Stage-1 has attained commercial maturity with 15 Pressurised Heavy Water Reactors (PHWRs) based on natural uranium in operation and 3 under construction. The second stage technology based on Fast Breeder Reactors using Uranium^{238} and Plutonium^{239} has been developed for commercial application. The third stage technology for utilization of Thorium^{232} has already been demonstrated through a pilot plant Kamini, located at Kalpakkam, Tamilnadu. Further development on advanced Thorium^{232} reactors to ultimately use Thorium^{232} resources on a commercial basis is in progress.

Considering the sequential nature of the programme, and the lead time involved at each stage, it is important to realize that direct thorium utilization as fuel will take time. Therefore, Innovative designs of reactors for direct use of thorium is also in progress. The technologies being developed include the Advanced Heavy Water Reactor (AHWR) and Accelerator Driven Systems (ADS). The ADS will be sub-critical systems using high-energy particles for fission. These systems will also produce little waste, as the actinides produced in the fission process will also be 'burnt'. The AHWR is an innovative concept, which is a bridge between the first and third stage systems. It uses light water as coolant and heavy water as moderator. It is fuelled by a mixture of Plutonium^{239} and thorium, with a sizeable amount of power coming from Thorium^{232}. India is also a partner in the international experimental initiative on harnessing fusion power for the future, the ITER project. India is supplying several components for the experimental reactor.

3.7.3.2 Additionalities to the three-stage programme of India

In parallel to the indigenous three-stage programme, additionalities based on imports have been introduced, essentially for faster nuclear power capacity addition in the near term, considering the lead times involved in the indigenous nuclear power programme. Two Light Water Reactors (LWRs) of 1000 MWe each are under construction at Kudankulam in technical cooperation with the Russian Federation. As capacity addition through the indigenous route is guided by the fuel cycle linkages of the three-stage programme, faster capacity addition in the near term to meet the needs of electricity can be possible through additionalities. The Government has taken initiatives for international cooperation in this regard. Setting up of additionalities will, however, depend on the developments in international cooperation.

3.7.3.3 Current status of nuclear power

India has developed and demonstrated the safe & reliable operation of PHWRs. India has also developed comprehensive capabilities is all aspects of nuclear fuel cycle. Apart from multi-dimensional R&D centres, front end and back end fuel cycle facilities have been set up. All other facilities, of the supply chain like heavy water, zirconium components and other special products have been set up. Indian industry has also been developed to manufacture critical nuclear components and equipment and take up execution of large nuclear package contracts. The performance of Indian nuclear power stations speaks of the maturity and mastering of the technology which has been duly recognized internationally, as evidenced by several international excellence awards and acclaims received. Today there are 17 reactors in operation with a capacity of 4120 MWe and 6 reactors with a capacity of 3160 MWe under construction. The location and capacity of Nuclear Power Plants is depicted in Figure 3.7.2.

Nuclear Power Corporation of India Limited (NPCIL), a Public Sector Undertaking under the Department of Atomic Energy was incorporated on September 17, 1987 to place nuclear power in the commercial domain. It is pertinent to mention here

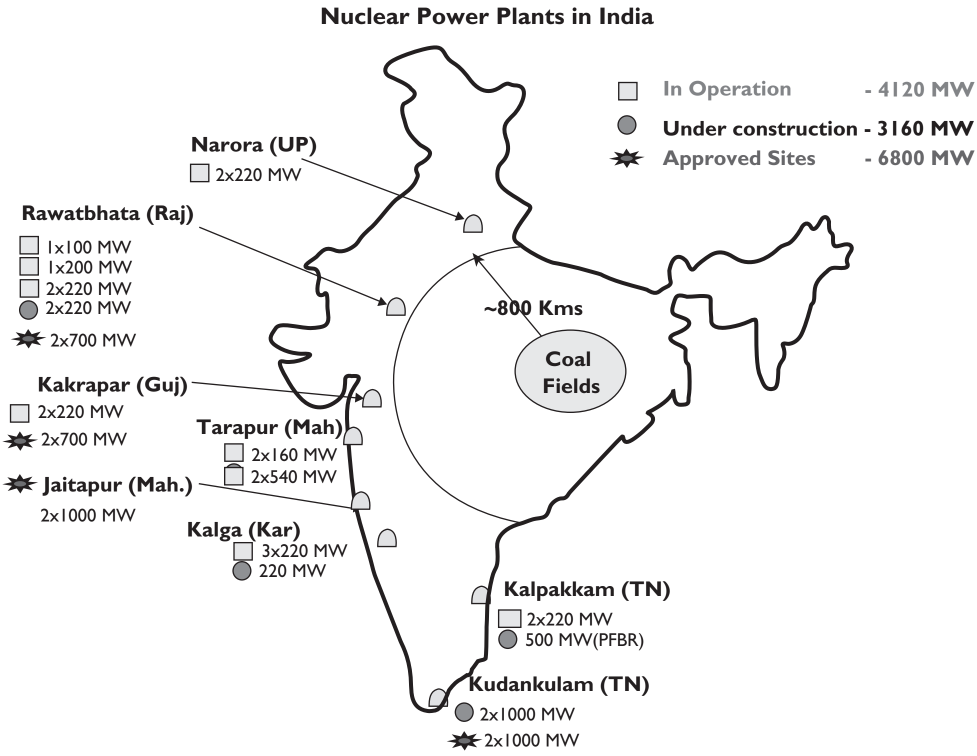


Figure 3.7.2 NPPs in India.

that NPCIL has demonstrated top class performance in all aspects of nuclear power including commercial viability.

3.7.3.4 *Significant achievements in nuclear power technology*

3.7.3.4.1 *Achievements in nuclear power plant operation*

Nuclear Power plants have registered high availability factor, safety performance and longest continuous operation comparable to international standards. The performance of the operating plants is depicted in the Figures 3.7.3 and 3.7.4.

The Indian nuclear power plants have also performed at par with international benchmarks. Figure 3.7.5 depicts the performance of NPCIL units vis-à-vis others worldwide.

3.7.3.4.2 *Safety performance*

The performance of Indian nuclear power reactors in terms of safety has been excellent, with 274 reactor years of safe, accident free operation. The releases to the environment have been a small fraction of the limit prescribed by the Atomic Energy Regulatory Board (AERB).

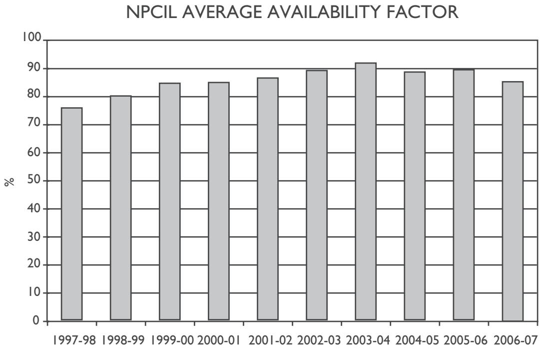


Figure 3.7.3 NPCIL A.F.

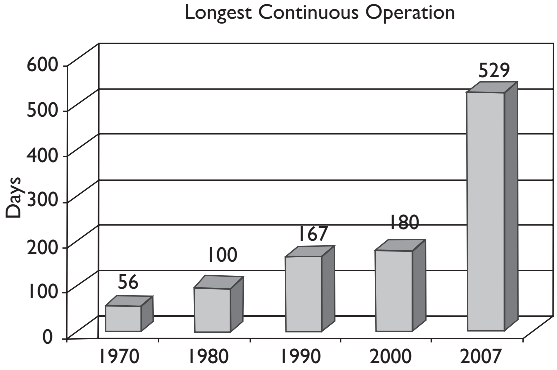
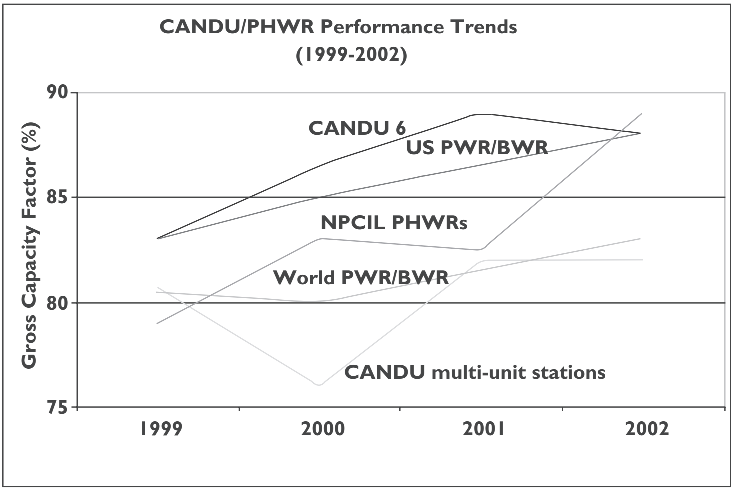


Figure 3.7.4 Continuous run.

3.7.3.4.3 Renovation & modernisation

NPCIL has developed and carried out unique R&M activities in its stations, namely Enmasse Coolant Channel Replacement (EMCCR) which has been successfully carried out at four reactors (Rajasthan Atomic Power Station-2, Madras Atomic Power Station 1&2 & Narora Atomic Power Station-1) with indigenous technology. En masse Feeder Replacement (EMFR) was carried out for the first time in the world in a PHWR at Madras Atomic Power Station-1. It has been carried out subsequently at Narora Atomic Power Station-1 & is presently underway at Rajasthan Atomic Power Station-2. The health assessment of Tarapur Unit #1&2 has been carried out using the latest and advanced techniques. Based on these studies, the plant life has been extended by replacing the important equipment/components. This includes replacement of Secondary Steam Generators (SSGs). In addition to this, safety upgradation of the units have also been completed successfully. The Tarapur units after renovation and modernization are operating with availability Factors near 100%.



CANDU Performance vs US and World PWR/BWRs

"At the end of 2002 average annual CANDU/PHWR Performance continued to show a gradual improvement, lead by the units of NPCIL (India).........'

"The NPCIL PHWRs showed a major improvement in GCF in 2002, exceeding US light water reuctor performance by almost 1%........."- Brian MacTavish, President, COG

Figure 3.7.5 International benchmarks.

Source: *COGnizant, vol. 8, Feb, 2003.*

Safety

273 reactor-years of safe, accident free operation
Doses to workers & Public a very small fraction of permissible limit

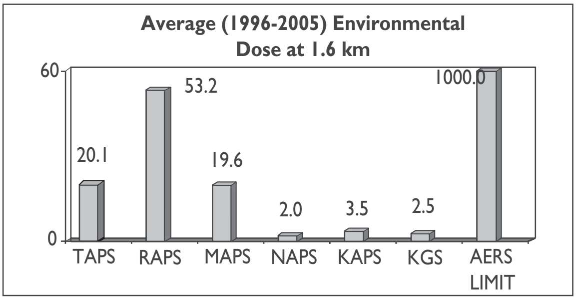


Figure 3.7.6 Safety performance.

3.7.3.4.4 Project construction performance

NPCIL has mastered and re-engineered the Nuclear Power Projects execution methodology and strategies and achieved reduction in gestation period. The construction and commissioning of TAPS 3&4 and Kaiga-3 in 5 years with substantial cost savings

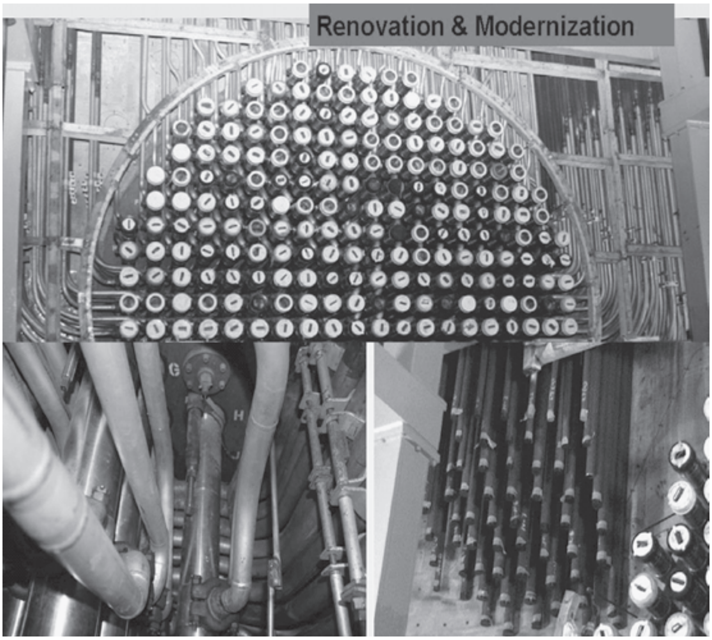


Figure 3.7.7 EMCCR & EMFR.

further endorses this. Figure 3.7.8 indicates the gestation time achieved in construction of nuclear power reactors in India is comparable to international standards.

3.7.3.4.5 Financial performance

- Total assets of NPCIL as on March 31st 2007 are Rs. 33,196 crores (~USD 8.3 billion).
- NPCIL is a consistent profit making, dividend paying company for the last several years.
- Financial Instruments of the company have highest safety rating AAA.
- Implementing programme with 70:30 debt equity ratio.
- No budgetary support since 2005 onwards.
- Future programmes of up to 10,000 MWe to be funded through reserve cash surplus and internal accruals.

3.7.4 Future plans – Nuclear reactors planned & capacity buildup

DAE/NPCIL vision is to achieve 20,000 MWe by the year 2020. The XI Plan proposals envisage setting up of 8 indigenously designed 700 MWe PHWRs, and 10 Light water Reactors of about 1000 MWe each, based on imports. In addition pre-project activities for setting up of 4 FBRs and an Advanced Heavy Water Reactor (AHWR) are also planned to be taken up in the XI Plan (2007–2012). The 4 FBRs will be taken

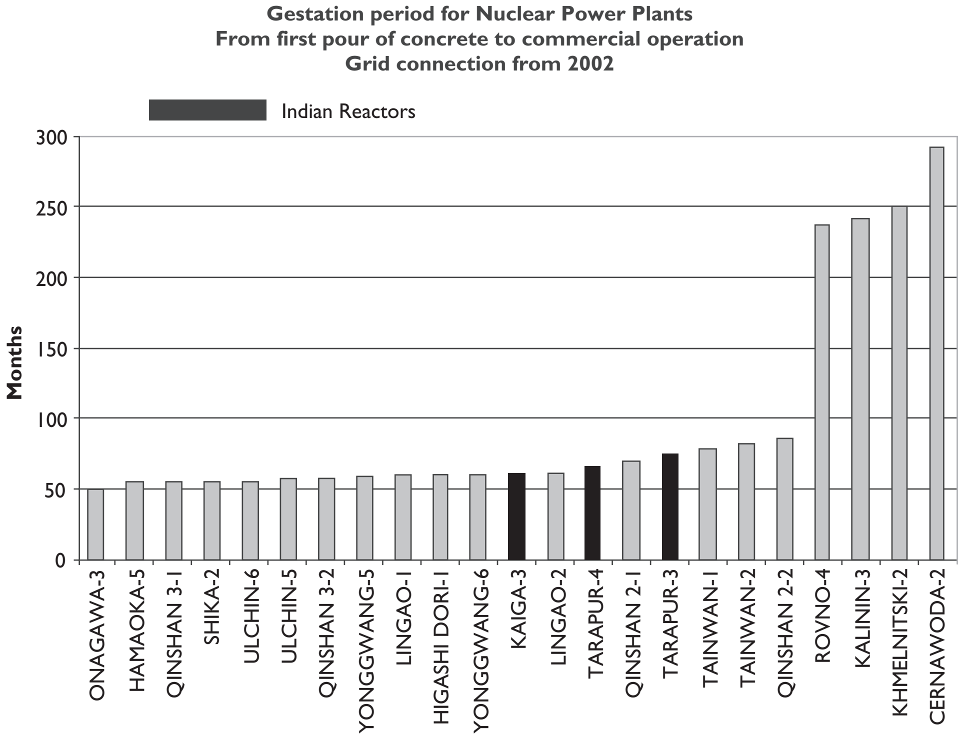


Figure 3.7.8 Construction performance.

up in the XII Plan (2012–2017). Summary of the capacity buildup, based on the XI Plan proposals would be as in Figure 3.7.9.

The vision 2020 document of the Department of Atomic Energy had envisaged reaching a nuclear power capacity of about 20,000 MWe by the year 2020. The possible nuclear power capacity beyond 2020 has been estimated by DAE to be as follows:

	Capacity (GWe)	
Year	*Lower Growth Scenario*	*Higher Growth Scenario*
2030	48	63
2040	104	131
2040	208	275

Source: Integrated Energy Policy, based on DAE inputs.

3.7.5 Safety management in Indian nuclear power plants

Utmost attention is given to safety in nuclear power plants. The overriding attention to safety encompasses the entire gamut of activities associated with nuclear power plants (NPPs) that is siting, design, construction, commissioning, and operation.

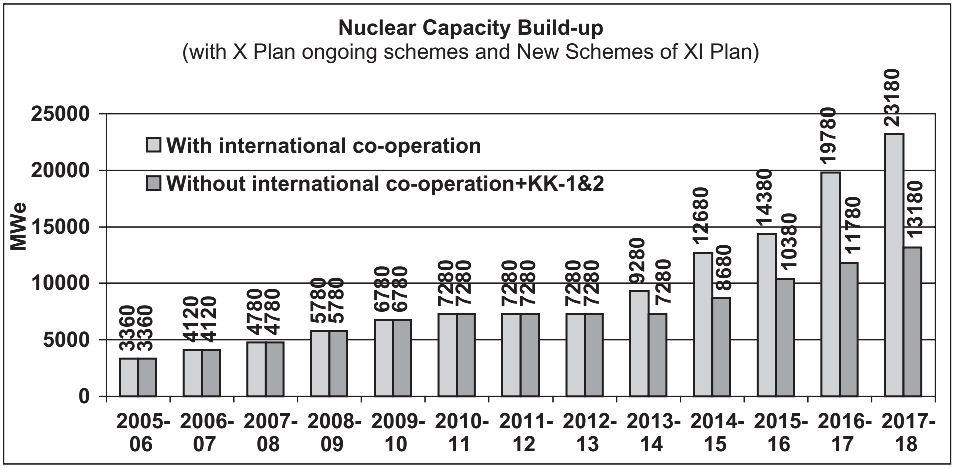


Figure 3.7.9 Capacity buildup.

A systematic approach using well-defined principles is followed in the design of the nuclear power plant to provide the required safety features adopting principles of defence-in-depth, diversity and redundancy.

In physical terms, a series of barriers exist in a nuclear reactor between the radioactive fission products in a solid fuel matrix and the public. Escape of radioactivity from the fuel will therefore require a breach in four barriers, namely Fuel, Fuel Cladding, Heat Transport System and Containment Building.

The regulatory mechanism is India is robust. The Atomic Energy Regulatory Board (AERB), an institution independent of the DAE, monitors and enforces safety in Indian nuclear power plants.

The review and implementation of Nuclear, Industrial and Radiation Safety in Indian NPPs through a three tier systems. These review mechanisms are:

- Review by Station Operation Review Committee (SORC). This committee comprising of senior experienced personnel in each station headed by Station Director, reviews the operation, adherence to technical specifications Radiological aspects and recommend the improvements.
- Periodic Internal Review for Safety assurance. These reviews are conducted by a team of officials independent to executing personnel. The status of implementation of recommendations is reviewed and monitored by Station Director/Project Director. The Safety Directorate of HQ, also monitors the functioning of these reviews.
- Corporate Reviews conducted by a corporate Review team comprising of the senior nuclear professions from NPCIL plants other than the reviewed plant and Corporate Office. The Corporate team reviews all functional areas, cross functional areas and safety; in specific. The findings of the Corporate Review team are reviewed by a high level committee at NPCIL. Head Quarter for implementation of recommendations by stations.

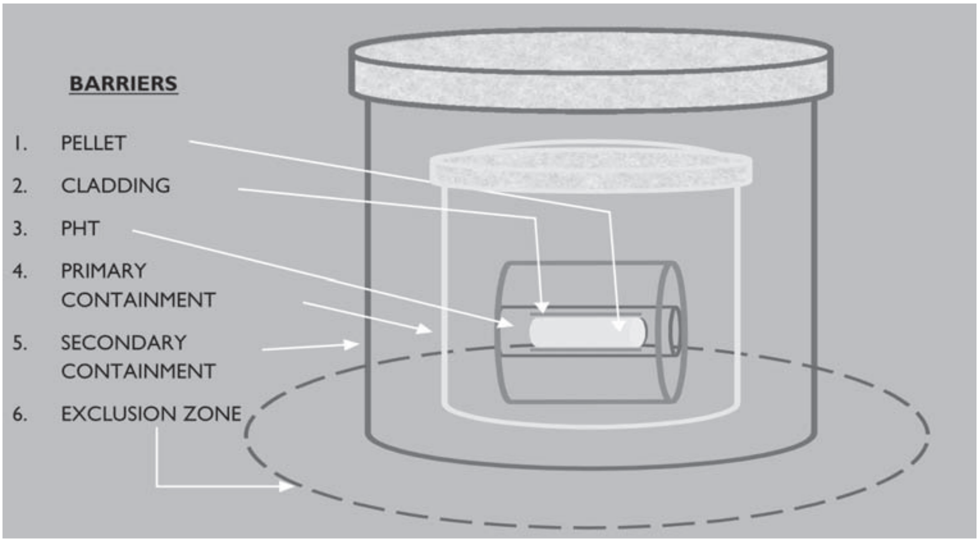


Figure 3.7.10 Barriers to release of *radioactivity*.

In addition to the above, Atomic Energy Regulatory Board (AERB) teams periodically review the safety of Nuclear Power Plants. These reviews are independent to above-mentioned reviews.

The reviews organised by World Association of Nuclear Operators (WANO), an international non-governmental organization by pooling the nuclear technology experts across the globe. Such reviews volunteered by the utility are also conducted once in Five years for each plant.

Industrial Safety in construction plant is of high significance due to the involvement of low educated unskilled workforce, which is large in number, employed for a specific purpose and time duration. Therefore, to ensure effective management of Industrial Safety in NPCIL Plants, a dedicated an independent Industrial Safety Section is in place. This group is headed by a senior and qualified safety professional who directly reports to respective Station/Project Head, to ensure safety is given the top most priority. The Safety Head and Safety Officers have been empowered to stop the work, in cases of hazardous work environment or inadequacy in procedures for Protection.

The effective management of Safety in Indian Nuclear Power Plants has registered 274 reactors years of accident free operation comparable to international standards.

3.7.5.1 Security management

Nuclear security has been an integral part of Atomic Energy Programme in India. Nuclear Security is of wide-ranging concern, nationally as well as internationally. Protection of Nuclear facilities and material against act of terrorism is one of the main objectives of Nuclear Security.

Various steps have been taken at Nuclear Power Stations. Significant among these is the graded access control for entry into the plant. The entry for main plant is through a turn style gate opened by using a magnetic card. This is further being augmented by use of Biometrics system.

The standard security guidelines are followed for controlling the entry of contract workers inside plant premises.

The various security issues are being regularly reviewed every quarter by High level committee i.e. Standing group for coordination and review of Security Arrangements (SG-CRSA) constituted by DAE.

3.7.5.2 *Waste management*

The waste generated during operation of nuclear power plants are of a very low activity level. They are managed at the site itself by appropriate methods. The combustible wastes are incinerated. The solid/liquid wastes are concentrated and immobilized in cement of polymer matrices and stored at the site in near surface storage facilities. The gaseous wastes (exhaust from ventilation of plant buildings) is filtered through High Efficiency Particulate filters for any particulate matter and discharged through a high stack.

A small quantity of high level wastes are generated during reprocessing of fuel, which is immobilized in inert glass matrix by a process of vitrification. India has developed the technologies in this regard and waste immobilization plants are in operation. The waste is stored in intermediate storage facilities before final disposal in a deep geological repository. The high level waste generated by a 1000 MWe station in its lifetime is of the order of 25 tons.

3.7.6 Merits of nuclear power

The power sector contributes significantly to GHG emissions, estimates of which vary from 40–50% of total emissions. Decarbonisation of the energy/power sector is one of the key recommendations made by various reports like the recent Intergovernmental Panel on Climate Change (IPCC) report in this regard (2007).

Nuclear power is environmentally benign and the life cycle Greenhouse Gas emissions of nuclear power are comparable to that of wind and Solar photovoltaic power. The life cycle emissions (from mining of ore to waste disposal) of nuclear power are very low, between 2.5 to 5.7 gCeq/kWh (grams of Carbon Equivalent per unit of electricity) against 206 to 357 in case of coal and 106 to 188 of gas technologies.

The base line CO_2 emissions in India from the predominant technology, coal are about 1 kg/kWh. Thus every unit of nuclear power generated saves 1 kg of CO_2 emissions. Thus nuclear power in India, which has generated about 284 billion units so far, has saved the earth of 284 million tones of CO_2. Every 1000 MWe nuclear power station to be set up in future will save about 7 million tons of CO_2 emissions every year. Nuclear power can be a major facilitator in decarbonising the energy sector and the same has been well recognized in the country's Integrated Energy Policy.

In addition, nuclear power is a compact source of energy and the transport infrastructure needed for nuclear fuel is very small. 10,000 MWe nuclear power capacity needs only about 300–350 tons of enriched fuel per annum, as against 35–50 million tons of coal needed for a coal fired thermal power station of the same capacity. It works to about a shipload or 20 trainloads per day. The pressure on rail, port and other infrastructure will be immense when large thermal capacity is added, apart from emissions arising out of transporting such large quantities of coal.

The land needed for setting up a nuclear power station is also less when compared to thermal coal fired power stations and hydel stations which involve large submergence of land.

3.7.7 Techno-economic aspects of production of Nuclear power – investments and tariffs

The current technology deployed in the country for generation of nuclear power is the PHWRs of the first stage. The standard size of these reactors has been 220 MWe. This size was adopted for compatibility with the grid capacity. As the grid capacity evolved and large carrying capacities became available, the 220 MWe design was scaled up to 540 MWe. Two units of 540 MWe have been set up at Tarapur in Maharashtra successfully, which are in operation. The design is being further scaled up to 700 MWe by permitting limited boiling of coolant, using the same core as that of 540 MWe. Thus a larger power output is being derived with minimum changes in hardware. As a result, the per MWe cost of 700 MWe reactors is expected to cost about 15% lower than the 540 MWe reactors.

As far as costs of Indian PHWRs are concerned, the overnight costs of 220 MWe reactors at 2007 prices have been in the range of Rs. 5.2 to 7.0 crore (USD 1.3–1.75 million)/MWe, while that of 540 MWe reactors has been about Rs. 6.0 crore (USD 1.5 million)/MWe at 2007 prices. The overnight cost of the 700 MWe reactors to be set up is estimated to be in the range of Rs. 5.1 to 5.2 crore/MWe (one USD = INR 40).

In addition, large capacity LWRs of about 1000 MWe LWRs have also been introduced as additionalities. The overnight cost of the Kudankulam Project (KK 1&2 – 2 × 1000 MWe), being set up in technical cooperation with Russian federation is 1220 $/kWe at 2003 prices.

The future plans include setting up of large capacity LWRs based on imports. The overnight costs of commercial nuclear power reactors in the world vary from 1200 to 2500 US $/kWe. There are no international numbers available for the cost/kWe for the various types of reactors available viz. AP-1000, EPR-1650, BN-1000, ABWR, ACR-1000 etc. The total cost will depend on the business models, participating organization/country, mode of implementation i.e. turnkey/technical cooperation, indigenous content and financial schemes. The cost towards construction and commissioning form a sizeable portion of about 40–45% of the total cost. Considering that these activities have to be carried out in India where the costs are low, is available closer to the PPP rate rather than the market rate by judicious choice in finalizing participating countries and the share of Indian industry (localization), a project costing between 1400 to 1500 $/kWe can be conceived.

As far as the tariffs are concerned these are regulated by the DAE in accordance with the Atomic Energy Act. The nuclear power tariffs are competitive with those of thermal power stations located away from coal pitheads. The tariffs of one station TAPS 1&2 is 94 paise/kWh (2.35 US cents/kWh) and that of three stations – MAPS, NAPS, KAPS below Rs.2 (5 cents/kWh). In the year 2006–07 the average tariff of nuclear power stations was Rs. 2.19 (about 5.5 cents/kWh). The tariffs of new plants to be set up, both indigenous and imported, is expected to be about Rs. 2.50 (6.25 cents/kWh) in the year 2015 (at 2015 prices).

Nuclear power is competitive with other conventional sources of power like coal, gas etc., at most locations. This has been the case in almost all the countries that have nuclear power programmes. Several cross country studies like the one by Organisation for Economic Cooperation and Development (OECD), have demonstrated that the lifetime levelised cost of generation of nuclear power is lower than that of coal and gas in most of the OECD countries studied, particularly at real discount rate of 5%. Internal studies by NPCIL have come to the same conclusion in respect of India. In respect of imported additionalities also, the studies have indicated that imported nuclear is among the most economical import options over the lifetime.

Nuclear power has a relatively higher capital cost (about Rs. 5.0 to 5.5 crore/MWe) when compared to thermal power (Rs. 4 crore/MWe) in India. However, its operating cost, particularly the fuel cost is much lower, thus making nuclear tariff competitive with coal thermal power at locations away from coalmines. It also makes nuclear tariffs much less sensitive to fuel price variations. Further, in India nuclear tariffs decline with time as they are front-loaded.

The externality cost of power generation, defined as the cost paid by the society at large on account of the impact on health and environment of nuclear power is lower by an order of magnitude. As per the European Commission report on externality costs (2003), the externality costs of nuclear power range from 0.2 to 0.7 Euro cents/kWh against 2–10 in case of coal and 1–4 Euro cents/kWh in case of gas.

In India, although the Integrated Energy Policy has introduction of environment taxes as one of its recommendations, it does not seem likely that they will be introduced anytime in the near future. If and when they are introduced, nuclear power will become even more competitive.

3.7.8 Conclusions

Because of its huge potential and techno-commercial viability, nuclear energy will play an increasingly important role in future in India's energy security. The rate of growth of nuclear share at the primary level is expected to be gradual till about 2050 and then rapid as conventional fossil fuel sources, particularly coal, approach exhaustion, or their extraction tends to become uneconomical. Further, with other energy applications of nuclear energy viz. production of hydrogen, desalination of water etc. is expected to grow the nuclear share at the primary level.

Acknowledgements

I thankfully acknowledge the contribution, of Mr. N. Nagaich, Chief Engineer (CP&CC) and Mr. B.V.S. Sekhar, Additional Chief Engineer (Corporate Planning) in the preparation of this paper.

3.8 ROLE OF NUCLEAR POWER IN THE ENERGY PORTFOLIO OF JAPAN

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Tokyo, Japan

3.8.1 Endowment of uranium and thorium resources of Japan

In addition to the estimated high cost for exploration on her domestic uranium ore, Japan is poor in uranium resources, which is only 7 thousand t-U, whereas the probable reserve in the world is 4.7 million t-U. Therefore, Japan now depends on the overseas resources for all uranium ores; the existing long-term procurement contracts with the producing countries are the key to the security of country's energy supply.

Neither milling processes (to make yellowcake) nor conversion factories (to uranium hexafluoride) are operated in Japan. However, a commercial factory of uranium enrichment adopting the gas centrifugation process is in operation from 1992. Three domestic companies also work on the fabrication of uranium fuels for supply to the domestic Light Water Reactors (LWR). The secured uranium resources overseas based on commercial contracts are in Namibia, Australia, Canada, UK, South Africa, France, USA, etc., and Japanese firms retain the share of mining interest in Niger, Canada and Australia. The total amount of 249 thousand t-U thus secured is 28 times larger than annual domestic demands of ca. 9 thousand t-U.

The present research work in Japan on the thorium fuel cycle is very limited; Furukawa et al. (1992) conducted the reactor design work in 1992 on the thorium molten-salt reactor "FUJI" for the electric power generation with a thermal output of 160 MW. Even if Japan wants to rely on the thorium-based nuclear energy in the future, the amount of natural resources of domestic thorium ores such as monazite is very limited and hence they will not be an object of commercial mining.

3.8.2 Present and projected consumption of nuclear energy per capita in relation to the primary energy sources in the energy mix

The first nuclear power plants in Japan began operation in 1966, and 55 reactors are currently in commercial operation. In 2006, the annual consumption of nuclear energy per capita is 23 GJ, occupying 13% of the primary energy consumption in the country. About 30% of the electric power is produced by nuclear energy in the same year. Eventually, these reactors will have to shut down. Looking ahead, the Framework for Nuclear Energy Policy, approved by the Governmental Cabinet in October 2005, states that Japan should work to ensure that nuclear power will continue to constitute over 30%–40% of total power generation after 2030. The Framework declares that Japan is committed to the development of next-generation LWRs to replace current reactors. This will be a national project that integrates the efforts of government, power suppliers and manufacturers.

In 2008, in the power sector, the energy-mix policy to attain lower carbon intensity in the future was examined and adopted in accordance with the governmental initiative to tackle with global warming in long term. The target portfolio of energy sources in 2020 in the power sector is that the nuclear power plus the renewables including hydro constitutes 50% of the total electric power generation, which is 10 points higher level than that in 2007.

3.8.3 Technologies to improve the production of electricity from uranium, investments (per kWe) and fuel costs (per kWh) of the present and projected nuclear energy

Japan has developed the research of nuclear power generation since the middle of the 1950s. A test power reactor, JPDR, started operation in 1963 and Tokai Power Station, the first commercial reactor went into commercial operation in 1966 with a generation capacity of 166 MW. Currently, 55 commercial nuclear reactors are in operation with a total generation capacity of 49,580 MW and about one-third of electricity comes from nuclear power. Japan will continue to develop nuclear power as a mainstay of non-fossil energy, while placing the highest priority on safety.

All of 55 commercial reactors for operation by Japan's electric utilities are LWR which uses light water (normal water) as coolant and moderator.

There are two types of LWRs – a boiling water reactor (BWR) and a pressurized water reactor (PWR). Each type is adopted in almost equal numbers in Japan, for the investment per kWe and running cost of electricity (in terms of kWh) are comparable for both types of LWRs.

The cost reduction, i.e. the efficiency improvement of the electricity production has been pursued in Japan by up-scaling of the unit: the electric output of one unit of LWRs has increased from 340 MW (Mihama-1 PWR in operation from 1970) to 1,358 MW (Shika-2 Advanced-BWR in operation from 2006).

The following Table 3.8.1 summarizes the investment of nuclear power in Japan. The construction costs for some of the power plants are collected from the websites and used for the estimation of the investment to unit kW capacity. Japan's investment to 55 LWRs until 2006 is estimated to be 254 thousand yen per kW capacity.

There are many cost estimation studies existing on various power generation systems for the comparison purpose; their assumption in the estimation differs, but the

Table 3.8.1 Deployment of commercial nuclear power in Japan.

Date of completion	*Number of unit*	*Generation power (MWe)*	*Estimated average investment per kWe (10^3 JPY)*
1970s	20	14,786	101
1980s	16	14,328	304
1990s	15	15,803	332
2000 – present	4	4,663	324
Total	55	49,580	254
present – 2017 (planned)	9	12,274	–

obtained cost results of electricity for nuclear power plants are around 6 – 7 JPY per kWh, and the fuel contribution to the cost is estimated to be 10%.

Japan is proceeding with research on the fast-breeder reactor (FBR) cycle. A fast breeder reactor can reduce the amount of nuclear waste and radioactive toxicity because it will dramatically improve the use of uranium resources. Moreover, using fuel where minor actinides are mixed with plutonium will increase proliferation resistance because the increased radioactivity will make diversion more difficult. Thus, the FBR cycle will contribute to the long-term stable supply of energy, reduction of nuclear waste and nuclear non-proliferation.

The "MONJU" FBR prototype reactor first reached criticality in 1994, but because of the leakage of secondary-system sodium in 1995, the unit was shut down. Refurbishment has now been completed and tests are under way to resume operations. On the premise that FBRs can be commercially viable by 2050, the Agency for Natural Resources and Energy of the government has developed a pathway setting out the following goals:

1 Aim at the completion of a fast breeder demonstration reactor and related cycle facilities by around 2025.
2 Start operating a second processing plant by the time the Rokkasho Reprocessing Plant stops operation (around 2045); reuse recovered plutonium in the fast-breeder reactor.

3.8.4 Hazards, risks, safety, policy, management, etc. of nuclear industry

Japan's spent fuel has been reprocessed in the UK and France. However, in order to further enhance energy security, Japan has turned to recycling spent fuel itself to establish nuclear power as a domestic energy source, because Japan has few natural resources. In addition, it conserves uranium resources, and the volume of high level waste (HLW) is reduced to less than half by reprocessing spent fuel, which lightens the burden on final disposal of HLW.

Japan Nuclear Fuel Limited (JNFL), owned in large part by Japan's electric power companies, plays an important role in completing the nuclear fuel cycle. In Rokkasho Village, Aomori Prefecture, JNFL currently operates three types of facilities: the Uranium Enrichment Plant, the Vitrified Waste Storage Center for high-level radioactive waste and the Low-level Radioactive Waste Disposal Center. The company is currently preparing for commencement of overall operations at its large-scale Reprocessing Plant, and it is also planning to construct a MOX Fuel Fabrication Plant.

The Tokyo Electric Power Company's Kashiwazaki-Kariwa Nuclear Power Plant (Units 1 to 7) experienced more significant vibration than assumed in design, due to the Niigataken Chuetsu-Oki Earthquake that occurred on July 2007. This resulted in successful operation of important safety-related functions, ranging from the automatic shutdown function to the function to lead a reactor to safe and stable shutdown conditions. On the other hand, the earthquake developed safety concerns among the public because of improper trouble shooting of fire and improper public relations activities immediately after the earthquake, in addition to the ground motion significantly exceeding than assumed in design. The Nuclear Safety Commission and the Nuclear and Industrial Safety Agency of the government requested utilities to conduct a seismic safety checks of nuclear power plants (back checks) earlier than planned in light of the new "Regulatory Guide for Reviewing Seismic Design of Nuclear Power Reactor Facilities" established by the Nuclear Safety Commission in 2006.

As for the geological disposal of high-level radioactive waste (HLW), some local government considered applying to be a candidate for a survey to select preliminary study areas for HLW disposal facilities. However, there are no areas where preliminary study has been done now. At the moment, there is a delay in the site selection process. In order to improve the situation, the government and utilities decided to fundamentally strengthen activities to foster understanding that the construction of disposal facilities is beneficial to the general public, promoting mutual understanding with the public and with local government through dialogue.

3.8.5 Health impacts of radiation environment (quality of air, water, soil, etc.) of the projected nuclear energy use

Each power plant in Japan has multiple safety measures, which are designed on the assumption that they must ensure the safety of the neighboring communities so that there will be no adverse impacts on their health.

To begin with, nuclear power plants are designed to prevent abnormal incidents from occurring. Secondly, even if abnormal incidents do occur, nuclear plants are also designed to prevent the potential spreading of abnormal incidents and leakage of radioactive materials around plants, which may cause adverse impacts on the surrounding environment.

Japanese power plants utilize redundant safety measures to keep residential communities around them safe at all times. Measures to be put into action in order to ensure safety during unusual events can be summarized in the following three points: To stop operating reactors, To cool down reactors so as to remove heat from nuclear fuel, and To contain radioactive materials.

Measures against earthquakes are also important in the tectonically active country like Japan. Followings are the guidelines for the measures:

1 Not to construct nuclear plants on an active fault.
2 To construct nuclear plants on a bedrock (in general, shakes on bedrock are about one-third to half as large as those on an outermost stratum).
3 When seismic detectors in nuclear power plants detect a strong tremor, a nuclear reactor will automatically stop operation.

Environmental radiation monitoring is conducted in accordance with the regulation. Electric utilities manage radiation exposure so that local residents around nuclear power plants receive less than 0.05 mSv per year. In reality, radiation exposure is much lower than 0.05 mSv, and is actually less than 0.001 mSv.

Local governments as well as utilities independently measure radiation dose in the air by radiation monitoring systems around nuclear power plants. In addition, they periodically collect seawater, soil and agricultural as well as sea products to measure and analyze them for radioactivity and to ensure that power plants have no adverse impact on the surrounding environment.

3.8.6 Implications of the projected nuclear energy use on GDP per capita and quality of life

In Japan, the successful deployment of commercial nuclear power for 40 years was conducted by the private sector. Inevitable replacement of the existing LWRs will be scheduled around 2030. The public acceptance level of LWRs in Japan is enough to the replacement, because there are no severe accidents in the operation of commercial LWR power stations. Hence even if the R&D on the fast-breeder is slow and retarded, the nuclear energy use on GDP per capita will remain to the present level.

The quality of Japanese life strongly depends on the overseas availability of natural resources including uranium and the fossil fuels, rather than on waste or side-effect problems on the energy systems, such as air pollution from the fossil fuel combustion and radiation from the nuclear energy use. If the times come when Japan needs the fast-breeder or the thorium fuel cycle, it means that the quality of life in Japan becomes in danger due to the difficulties in procurement of natural resources from overseas.

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SECTION-IV
Renewable energy resources

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PREAMBLE

As per the definition of the International Energy Agency, Paris, renewable energy resources include renewable combustibles and waste (solid biomass, charcoal, renewable municipal waste, gas from biomass and liquid biomass), hydro, solar, wind and tide energy. In 2006, world Total Primary Energy Supply (TPES) was 11,741 Mtoe, (millions of tonnes of oil equivalent) of which 12.7% or 1493 Mtoe was produced from renewable energy sources. The percent shares of the main fuel categories in total renewables are: Combustible renewables and waste (78.1%), Hydropower (17.5%), Geothermal, solar, wind, tide, etc. (4.4%).

i *Hydropower*: Presently, hydropower accounts for 90% of the renewable power generation. IEA estimates that by 2050, hydropower capacity could go up by 1700 GW, producing 5000–5500 TWh/yr. Though the world's technically feasible hydropower is 14,000 TWh/yr, the realistic potential is 6000 TWh/yr. Around 808 GW of hydropower is in operation or under construction. Hydropower is one of the cheapest ways of producing electricity. Most plants have been built many years ago, and their capital costs have already been amortized. The capital costs of new plants vary from USD1000/kW in developing countries to USD 2400/kW in OECD countries. Generating costs vary from USD 0.02–0.06/kWh. Large-scale hydropower projects often become controversial, as they tend to affect water availability downstream, inundate historic sites and ecosystems, and have serious socioeconomic impacts because of the need to rehabilitate displaced populations. An environmentally-friendly energy conversion option is the small-scale hydropower generators which are designed to run in-river. This self-standing application could replace diesel generators. An innovative approach is the generation of hydropower from pumped storage systems involving two or more reservoirs at different heights. Typical electricity storage efficiency is 80%. Pumped storage capacity worldwide is 100 GW. An issue of concern is how climate change will affect the hydropower potential and economics, because of depleted river flows.

ii *Geothermal and ocean energy*: Geothermal power is currently in use in Indonesia, Mexico, New Zealand, Nicaragua and USA. Commercial geothermal plants are of three types: dry steam, flash steam and binary cycle. Total capacity of geothermal power is 10 GW in 2007, generating 56 TWh of electricity. Capital costs vary from USD 1150–5500/kW of installed capacity. Generating costs range from USD 0.015–0.025/kWh.

iii *Wind power*: Wind power is economically viable in areas where the wind speed is 2.5–25 m/s. Wind power has grown 50 times since 1990 to the present global installed capacity of 94 GW. In 2006, wind turbines produced 152 TWh of electricity, which is less than 1% of the global electricity supply. Wind power is experiencing a double digit growth. By 2050, wind power may account for 9–12% of the global electricity generation. Today, five countries (Germany, USA, Spain, India and China) account for 73% of the global installed wind capacity. Offshore wind power is at the pre-commercial stage of development. Its advantages are higher capacity factors, higher wind speeds leading to 50% greater input, and lower visual impact. It is, however, more expensive than onshore wind power.

The cost of the wind turbine accounts for 74–82% of the onshore wind power station. Wind power costs US cents 8.9–13.5/kWh, depending upon the local wind conditions.

iv *Biomass and Bioenergy*: Bioenergy is not only the largest contributor to renewable energy presently but also has the highest technical potential among the renewable energy resources. Biomass is used inefficiently for traditional domestic cooking and space heating. According to a projection by IEA, biomass use would increase four-fold by 2050 (150 EJ/yr or 3604 Mtoe/yr.). This would involve the delivery of 15,000 Mt of biomass to the production plants annually, with half of this coming from crop and forest residues, and the rest from purpose-grown energy crops. The projected use of bioenergy would be as follows: about 700 Mtoe/yr for transport biofuels, about 700 Mtoe/yr to generate electricity (2450 TWh/yr), and 2200 Mtoe to produce biofuels, heating, and cooking (including production of dimethyl ether), and industry (including process steam from CHP (Combined Heat and Power) and black liquor (used for the extraction of lignin). By co-firing biomass with coal in steam turbines of about 100 MW capacity, electricity could be produced at USD 60–80/MWh. Biofuel from algae has great potential – much research is being devoted to cultivating specific algal strains suitable for biodiesel production.

v *Solar Power*: Solar power has two facets: Photovoltaics (PV) and Concentrated Solar Power (CSP). Solar energy currently provides less than 1% of the world's total commercial energy. Solar power has great potential both for Developing and Industrialized countries, and could account for 6–11% of the global electricity production. The PV market is growing rapidly in grid-connected and building-integrated systems in industrialized countries and in high-growth economies, such as those of China and India. Off-grid PV systems which will continue to be important in water-pumping, rural electrification and solar lanterns, constitute about 10% of the PV market. It is expected that by 2050, PV generation costs may go down to USD 0.05/kWh in sunny areas with more than 6.7 W/m^2 of radiation. According to IEA, the key technology developments that will have a great impact on the economics of PV are: "to increase the efficiency and reduce the material intensity and costs of c-Si modules; to increase the efficiency and life-span of thin-film modules; to develop third-generation novel devices, such as, ultra-high efficiency and ultra-low cost cells". In sunny areas, CSP is cheaper than PV for large on-grid plants, and could be combined with desalination plants. It is expected that between now and 2050, electricity from CSP may drop to USD 0.035/kWh. The key technology developments in CSP are: increase in the efficiency of heat mirrors, heat receivers and heat storage systems.

The Preamble draws extensively from IEA's *Energy Technology Perspectives, 2008.*

4.1 HYDROPOWER

4.1.1 Introduction

In 2006, world Total Primary Energy Supply (TPES) was 11,741 Mtoe (millions of tonnes of oil equivalent) of which 12.7% or 1493 Mtoe was produced from renewable energy sources. Hydropower accounts for 17.5% of the Renewables (i.e. 261.2 Mtoe). In 2006, the production of hydropower in the following countries (expressed in Mtoe) is as follows: (source: *Renewables Information, 2008*): Brazil – 30.0; Canada – 30.6; China – 37.6; France – 4.8; India – 9.7; Japan – 7.4; Norway – 10.2; Russia – 14.9; Sweden – 5.3; USA – 25.1. One Mtoe is equivalent to 11630 GWh.

4.1.2 Hydropower facilities

Making use of the force of falling water as a source of mechanical power has been in vogue since the ancient times (we are all familiar with the poem of the jolly miller of the Dee, who makes his living from the flour mill operated by the water impounded by the weir on the river). There are three kinds of hydropower facilities: (i) "Storage" projects (Aswathanarayana, 2001, pp. 191–195), (ii) "Pumped Storage" projects, and (iii) "Run-of-river" projects.

4.1.2.1 "Storage" projects

Large surface reservoirs are constructed to increase the availability of water during the periods of low flow or dry years. Though the construction of water reservoirs has been going on since ancient times, all the large reservoirs with a total volume of more than 50 km^3 have been constructed during the second half of the last century. According to Shiklomanov (1998), the total volume of the reservoirs of the world is about 6000 km^3, and their total surface area is upto 500,000 km^2. The volume of water in the reservoirs corresponds to about 5% of the annual rainfall on land or 15% of the annual runoff. They trap 2–5 Gt y^{-1} of sediments, which is about a quarter of the total sediment yield of the land. Thus, the reservoirs have a profound impact on the circulation of water on the land surface, discharge of sediments and nutrients to the sea. The evaporation from the surfaces of the reservoirs is considerable, and thus the reservoirs are one of the greatest users of freshwater. The map by Vörösmarty et al. (1997) shows the location of the major reservoirs in the world.

High dams, such as the Sardar Sarovar dam on the Narmada River in western India, and the Three Gorges Project on the Yangtze river in China, have drawn much criticism and agitations particularly on account of the hardship caused to the people who have been or will be displaced, on account of the submergence.

Life often faces us with difficult, even cruel choices. A community may have to choose between the interests of a community as a whole and that of a family. A swimmer, when attacked by a killer shark, may have to choose between foregoing his leg rather than his hand, as the only way to save himself (he can use his hand to fire the gun). The construction of a reservoir which could provide drinking water to (say) a million people, may entail the uprooting (say) 10,000 people from their ancestral homes and avocations, and causing them immense hardship. A choice cannot be avoided. There is nothing like free lunch, and it is not possible to make an omelet without breaking the egg!

The following is a heart-rending story about choices. It is a real story narrated to the author by a Polish Jewish emigre in Sweden. During the Second World War, he was serving as an Army officer. One day he came to know from a highly reliable source that next day, there was going to be a *pogrom* (massacre of the Jews) by the Nazis, in their village. Immediately, he sent a trusted confidant to his village to tell his wife that she should leave the village immediately the same night, with their two sons, aged 7 and 2 years, without informing any body in the village. The elder son was ill, and was not in a position to walk. It was just impossible for her to carry both the children. She was faced with the cruel choice of losing both the children, and saving the younger child. She abandoned her elder son, knowing full well that the Nazis would surely kill him. She left the house in the dead of the night carrying the younger son.

The following discussion about the high dams takes into account the lucid exposition about high dams by P.V. Indiresan in an article in "*The Hindu*" (Madras, India) of Dec. 1, 1999:

i Other things being equal, doubling the height of the dam, increases the water stored *eight* times and the power potential *sixteen* times. Also, for a given amount of storage, the higher the dam the smaller the area that will be submerged. *It therefore follows that the construction of the highest dam that is technically feasible is the best way to minimize submergence and hence the number of people to be displaced.* If, instead of a high dam, it is proposed to have a number of low dams, the aggregate of the areas submerged by them will be considerably more, and the amount of hydroelectricity that could be generated will be minimal. The amount of water available for drinking and irrigation may be unaffected, however.

ii In countries with monsoon climate (e.g. India), the rainfall is restricted to a few months of the year. It is also erratic. Instances are known where the annual precipitation in an area occurred in a matter of few days of intense downpour. Consequently, flash floods are common, and very few rivers are perennial. Under these circumstances, harvesting and storage of surface runoff in reservoirs is the only way to provide irrigation and drinking water round the year. The runoff in a watershed can be harvested both through a high dam on a river *plus* a series of small check dams over small streams, and the recharge of groundwater. This is not a case of *either/or* but *and*. However, there may be situations where an area is so arid (e.g. Sinai desert in Egypt or Thar desert in India) that check dams are of no avail. Thus, Egypt is irrigating some areas in the Sinai desert by the transfer of Nile water. But for the water from Bhakra high dam in Punjab, the greening of desert areas in Jaisalmer, Rajasthan, India, would not have been possible.

iii In tropical countries, there is intense evaporation. In India, it is about 1.2 m. In other words, irrespective of the depth of the water body, the top 1.2 m layer of water in a reservoir will be lost due to evaporation. If the reservoir is (say) 100 m deep (because of a high dam), the loss due to evaporation would be only 1%. On the other hand, if the reservoir is shallow, (say, about 10 m), the loss due to evaporation would be 10% of the total storage.

Thus, in the ultimate analysis, a country or a community may have to make the choice, one way or the other. Indiresan is critical of the agitators whose sole aim is to stop the construction of high dams. This is a negative approach. Such agitators rarely, if ever, come up with techno-socio-economically viable alternatives, which can lead to benefits similar to the high dam. Indiresan suggests some practical steps to ease the problems arising from high dams: (i) Engineers should confine themselves only to building dams, and agronomists (not engineers) should manage water allocation, as is the practice in USA, (ii) The resettlement process should be handled by specialists, (iii) There should be complete transparency about all aspects of the dam, reservoir, submergence, etc., (iv) The displaced persons should be offered a package of benefits (such as retraining for the new jobs that will be created), and not just monetary compensation.

4.1.2.2 Three Gorges project (China): A case study

The advantages and disadvantages of the high dams are sharply manifest in the case of the Three Gorges project on the Yangtze River, which is the largest hydroproject in the world. It is a multi-purpose project, involving flood control, power generation, navigation, aquaculture, tourism, ecological protection, transfer of water from south to north, water supply for drinking and irrigation, etc. (Yangbo, 1998).

That the dimensions of the Three Gorges project are mind-boggling should be evident from the following particulars: Total storage capacity: 39.3 billion (B) m^3; Normal pool level: 175 m; surface area: 1084 km^2. Power generation potential of the system: 105 B kWh; Deep navigational channel for 660 km between Chongquin and Yichang allowing 10,000 t ships to sail – raising the shipping capacity to 50 million tons, and cutting the shipping costs by 37%.

The most important purpose of the Three Gorges Project is flood control. The middle and lower reaches of the Yangtze River are well developed in agriculture and industry. These areas are highly vulnerable to flooding, because the flood level can be 6–17 m higher than the ground level of the adjacent plain. According to statistics, there have been 214 occurrences of disastrous floods during the last 2000 years, with a recurrence interval of about 10 years. The Three Gorges Project can protect the lives and properties of more than 15 million people, and 1.53 million hectares of farmland in the downstream plains, against the biggest flood in 100 years, and even the possible biggest flooding in 1000 years.

The shortage of water in North China is hindering its development. The Three Gorges Project will alleviate this shortage by facilitating the transfer of 70 B m^3 of water from south to north.

The Three Gorges Project was criticized on the ground that it is very expensive, that a large number of people will be displaced, and that valuable historical and sacred sites will be permanently lost due to submergence, that it will get silted up, etc. All these criticisms are undoubtedly valid. It should be said to the credit of the Chinese Government that they took great pains to minimize the sufferings of the displaced people. Every village and town have been told long in advance where they will be relocated, and how they will earn their livelihood in the new setting. Habitations and service facilities (such as, schools and hospitals) have been built in advance in the new locations, and the government helped the families to shift their personal effects to the new locations. Many persons have been retrained to take advantage of the new kind of jobs generated by the project. Key historical sites were excavated and shifted to higher positions. There have of course been cases of beauracratic bungling and corruption, and some people were extremely unhappy to leave their ancestral homes.

There is little doubt that on balance, the benefits from the Three Gorges Project far outweigh the disadvantages and the hardship caused to people. *The most important point to bear in mind is that the level of flood control, power generation and navigation achievable by the high dam of the Three Gorges Project cannot just be realized through a number of low dams.*

4.1.3 Pumped storage hydroelectricity

When there is more generation of electricity than the load available to absorb it (as during nights), excess generation capacity may be used to pump water into a reservoir at a higher elevation. When the electricity demand is high (as during daytime or due to the failure of a component of the grid), water is released back into the lower reservoir through the turbine, generating electricity. Also, Francis turbines, which are reversible turbine/generator assemblies, are capable of acting as both a pump and a turbine, could be used, as needed. One m^3 of water atop a 100 m tower, has the potential energy of about 0.272 kWh. Pumped storage is thus an effective way of storing energy through water. The two reservoirs may be man-made or natural.

Pumped storage is a high capacity form of grid energy storage presently available. It can be used to flatten out load variations on the power grid, which may be linked to coal-fired plants, nuclear plants or renewable energy power plants. In the context of the back-up provided by pumped storage, these plants could continue to operate at peak efficiency (Base Load Power plants), while reducing the need for "peaking" power plants that use costly fuels. Thermal plants are less able to respond to sudden changes in the electricity demands, and may cause voltage and frequency instabilities. In contrast, pumped storage plants, like the normal hydropower plants, can respond to load changes almost instantly (less than 60 seconds). Pumped storage is expected to become important for load balancing in tandem with large capacity solar and wind mill plants.

A recent technological development is the variable speed turbines which can generate electricity in synchronization with the network frequency.

Pumped storage system involves the evaporation losses from the exposed water surface and conversion losses. Approximately 70–85% of the electrical energy used to pump the water to the elevated reservoir is regained, depending upon the capital costs and geographic setting. This loss of about 20% of electricity is more than compensated by selling more electricity during periods of *peak* demand, when the electricity prices are highest.

Pumped storage capacity worldwide now is about 100 GW, which is about 2% of the hydropower generation capacity. Pumped storage capacity has the potential of 1000 GW, which is roughly half of the global hydropower potential (Taylor, 2007).

4.1.4 "In-river" small-scale hydropower projects

Small-scale hydropower projects are designed to run in-river. These are environment-friendly energy conversion options as they do not affect the river flows significantly.

They can be stand-alone applications to serve rural communities or as replacements to diesel generators.

Technology needs of small power stations are as follows (source: *Energy Technology Perspectives*, 2008, p. 391):

Equipment: Turbines with less impact on fish populations; low-head technologies; in-stream flow technologies.

O&M practices: Package plants which require only limited O&M.

Hybrid systems: Wind-hydro systems; Hydrogen-assisted hydrosystems.

4.1.5 Resources and costs

Presently, hydropower accounts for 90% of the renewable power generation. The total hydropower potential in the world is estimated to be 2000 GW (Taylor, 2007). IEA estimates that by 2050, hydropower capacity could go up by 1700 GW, producing 5000–5500 TWh/yr. Though the world's technically feasible hydropower is 14,000 TWh/yr, the realistic potential is 6000 TWh/yr. Around 808 GW of hydropower is in operation or under construction. Hydropower is one of the cheapest ways of producing electricity. Most plants have been built many years ago, and their capital costs have already been amortized. The capital costs of new plants vary from USD 1000/kW in developing countries to USD 2400/kW in OECD countries. Generating costs vary from USD 0.02–0.06/kWh.

Large-scale hydropower projects often become controversial, as they tend to affect water availability downstream, inundate historic sites and ecosystems, and have serious socioeconomic impacts because of the need to rehabilitate displaced populations. Installing fish passage systems can reduce the impacts on migrating fish populations.

An issue of concern is how climate change will affect the hydropower potential and economics, because of depleted river flows. As a dam may have a lifetime of about 100 years, the depletion of water supply due to climate change or the reduction in the storage capacity of the reservoirs due to sedimentation, have to be kept in mind in working out the economics. Some flow is needed for ensuring the life and reproduction of the indigenous fish. Similarly, some flow is needed for development. There is no simple way to determine the minimum flow in a river which will satisfy the environmentalists and developers at the same time, and therein lies the problem.

The investment and production costs of hydropower are given in Table 4.1.1, assuming 10% discount rate.

Table 4.1.1 Investment and production costs of hydropower.

	Investment cost (USD/kW)			*Production cost (USD/kW)*		
	2005	*2030*	*2050*	*2005*	*2030*	*2050*
Large hydro	1000–5500	1000–5400	1000–5100	30–120	30–115	30–110
Small hydro	2500–7000	2200–6500	2000–6000	56–140	52–130	49–120

Source: *Energy Technology Perspectives*, 2008, p. 400.

4.2 GEOTHERMAL AND OCEAN ENERGY[1]

4.2.1 Introduction

The vertical temperature gradient in the earth's crust has an average of 30°C/km. It varies from 10–20°C/km in the Precambrian shield areas to 30–50°C beneath tectonically active areas. There are areas where the gradient is as high as 150°C/km. Areas of high heat flow (more than 2 HFU – Heat Flow Units) on the continents are characterized by hot springs and products of Tertiary volcanic activity. Lardarello (Italy), Geysers, Casa Diablo, Niland (USA), Wairakei and Waistapu (New Zealand) Hvergardi (Iceland), Pauzhetsk (Russia), Otake and Matsukawa (Japan) are some of the areas where geothermal power is being tapped economically.

High-temperature geothermal energy sources can be used to generate electricity. Lower temperature geothermal sources are best used for space heating (90% of all homes in Reykjavik, Iceland, are heated this way), domestic and industrial refrigeration, heating of green houses and animal shelters, crop drying, dehydration, etc. Freshwater is a highly valuable by-product of tapping geothermal sources. When brackish water is desalinated by geothermal energy, useful chemicals are obtained as a bonus.

Among the geothermal regions, fault block terrains with Quaternary volcanism (like those of the East African Rift system) have the highest average reservoir temperature (~250°C). In order to be economic, a geothermal well should be able to produce more than 20 tonnes/hr of steam. Geological criteria (such as, age, structure, thermal manifestations), geochemical criteria (like the dissolved silica content, Na/K ratios of surface and spring waters), and geophysical studies (deep resistivity surveys, heat flow measurements) are used for prospecting for and evaluation of, geothermal energy sources.

Geothermal energy has several advantages: (i) It is non-polluting and has no carbon footprint, (ii) It is of large magnitude – the heat stored in the earth is estimated to be about 5 billion EJ, which is 100,000 times more than the world's annual energy use, (iii) It is available all the year round, and production costs are low (see Table 4.1.1). There are, however, some drawbacks: (i) Air pollution may sometimes be caused by H_2S, CO_2, NH_3, Rn, etc. gases vented into the air, (ii) Low magnitude earthquakes may be triggered and land subsidences may take place due to changes in the reservoir pressure, (iii) The overall efficiency of geothermal power production (15%) is less than half of the coal-fired plants, (iv) Drilling costs are high (USD 150,000–250,000 per well).

The total capacity of geothermal power plants in the world is 10 GW in 2007, generating 56 TWh/yr of electricity. Indonesia, Mexico, New Zealand, Nicaragua and USA are active in this area.

There are three kinds of commercial geothermal plants, depending upon the temperature of water.

i Dry steam plants, which use direct steam resources at temperatures of about 250°C,
ii Flash-steam power plants which make use of hot, pressurized water at temperatures hotter than 175°C. In these types of plants, pressure is lowered when the

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[1] Aswathanarayana (1985, pp. 159–162) summarized the geological and economic aspects of geothermal energy.

high temperature, high pressure fluids enter the plant, thereby making them boil or flash. The steam is used to run the turbine, and water is injected back into the reservoir.

iii Binary plants which use geothermal resources at temperatures of about 85°C. The heat contained in the hot water is exchanged through the use of a fluid that vaporizes at lower temperatures. This vapour drives a turbine which generates power. Hot water in the reservoir fluid generally contains dissolved salts, but since it is a closed system, the dissolved salts do not affect the environment. The fluids with the dissolved salts are injected back into the reservoir. As the system is environmentally benign, the binary power plants have become popular.

Large scale geothermal plants are currently possible in high heat flow areas such as, plate boundaries, rift zones, mantle plumes and hot spots, that are found around the "Ring of fire" (Indonesia, The Philippines, Japan, New Zealand, Central America, the west coast of USA) and the rift zones (East Africa, Iceland).

A geothermal field need not have a surface manifestation in the form of a hot spring.

In fact, fields of dry, hot rock are the most promising sources of geothermal energy, though technology for their exploitation is yet to be commercially developed. On the basis of abnormally high thermal gradients (ten times the normal value of 20°C/km), David Blackwell found at Marysvale, Montana, USA, a 31 sq.km. area underlain by hot rock (at temperature of over 400°C) at a depth of 1 km, which is accessible to drilling. It has been estimated that this field alone could provide a supply of one-tenth of America's electricity needs for 30 years.

4.2.2 Costs

In the case of geothermal electricity, well drilling accounts for half of the capital cost. Efforts are being made to bring down these costs. The capital costs vary from USD 1150/kW of installed capacity for large, high-quality resources, to USD 5500/kW for small, low-quality resources.

The temperature of the geothermal fluids determine the electricity generation costs.

The operating costs are in the range of US Cents 2–5/kWh for flash and binary systems, excluding investment costs. In the case of the Geysers Field, California, the operating costs are US Cents 1.5–2.5/kWh. In Europe, generation costs range from US cents 6–11/kWh for traditional geothermal plants.

4.2.3 Research & Development

Enhanced Geothermal Systems (EGS) tap the heat from the hot, dry rock underground.

Water becomes steam when it is pumped through boreholes and encounters the hot rock. When steam returns to the surface, it is used to generate electricity through a binary generator. The water is recirculated continuously. A number of countries are seeking EGS power – Australia (5.5 GW), USA (100 GWe), China and India (100 GW). Switzerland is planning to build 50 EGS plants of 50 MW capacity (i.e., totaling 2.5 GW), to provide one-third of the electricity requirements of the country. EGS is not an unmixed blessing – an EGS plant near Basel, Switzerland, triggered a minor earthquake of magnitude 3.4 in Dec. 2006. Another problem with EGS is the large requirement of water – a small 5 MW plant requires 8500 t/d of water. A large scale plant may requires ten times more water.

Five km deep geothermal wells are highly productive, as the steam conditions are much more favourable (430–550°C; 230–260 bars), but drilling costs are prohibitively high (USD 5 million per well). Geothermal plants based on deep wells will become economical when the drilling costs come down (Bjarnason, 2007).

4.2.4 Ocean energy

Ocean energy technologies for the generation of electricity are in the early stages of development. Among ocean energy technologies, only wave energy and tidal energy have good potential, and are being actively developed in 25 countries. Technologies based on temperature and salinity gradients and marine biomass have little chance of becoming commercially viable in the near future.

The use of tidal energy to generate power is similar to that of hydroelectric power plants. A dam or barrage is built across a tidal bay or estuary where there is a difference of more than five metres between the high tide and low tide. Water flowing in and out of the dam runs the turbines installed along the dam or barrage, and generates electricity. Tidal plants have periods of maximum power generation every six hours. During periods of low electricity demand, extra water is pumped into the basin behind the barrage, on the analogy of pumped storage.

Apart from grid-connected electricity generation, ocean renewable energy could also be used for off-grid electricity generation in remote areas, aquaculture, desalination, production of compressed air for industrial applications, integration with other renewable energy resources, such as offshore wind power, solar PV, etc.

Power plants based on tidal barrages have been in operation at La Rance in France (240 MW, built in 1960s), and Annapolis Royal in Canada (20 MW, built in 1980s).

Korea is constructing a 254 MW tidal energy plant, at the cost of USD 1000/kW.

Tidal barrage projects are more environmentally intrusive than wave and marine current projects. The adverse environmental impact of tidal barrage projects is sought to be reduced by integrating oscillating water turbines with breakwater systems that convert water pressure into air pressure and use the compressed air to drive a Wells turbine. Such breakwaters linked projects (about 0.3 MW capacity) are being developed in Spain and Portugal. Portugal is also actively developing wave energy plants with the goal of achieving 23 MW by 2009.

The potential for wave energy plants, typically 0.3 MW capacity, depends on wave heights. The wave potential increases towards the poles, but is site dependent. The European Atlantic coast, the North American Pacific Coast, and Australian south coast, hold promise.

Ocean Thermal Energy Conversion (OTEC) plants which are based on harnessing the temperature gradients in the ocean, are in operation in India. Heat pumps powered by oceanic thermal energy are being used for heating and cooling in a number of countries.

OTEC plants are expected to become operational after 2030.

Norway is building a 10 MW demonstration plant to harness the energy based on salinity gradients.

Table 4.2.1 Investment and production costs of geothermal and ocean energy.

	Investment cost (USD/kW)			*Production cost (USD/kW)*		
	2005	*2030*	*2050*	*2005*	*2030*	*2050*
Geothermal						
hydrothermal	1700–5700	1500–5000	1400–4900	33–97	30–87	29–84
hot dry rock	5000–15,000	4000–10,000	3000–7500	150–300	80–200	60–150
Tidal barrage	2000–4000	1700–3500	1500–3000	60–100	50–80	45–70
Tidal current	7000–10,000	5000–8000	3500–6000	150–200	80–100	45–80
Wave	6000–15,000	2500–5000	2000–4000	200–300	45–90	40–80

Source: *Energy Technology Perspectives*, 2008, p. 400.

4.2.4.1 R&D and costs

Considerable R&D effort is needed to ensure the commercial viability of ocean energy systems: Basic science research on wave behaviour and dynamics of wave absorption, applied science research on the design of supporting structures, turbines, foundations, engineering designs in regard to hull design, power takeoff systems, etc.

The design of tidal barrages has to take into account the possible adverse effects on mudflats and silt levels in the estuaries and wildlife living in and around the estuary.

The breakdown of the projected investment costs for shoreline and near shore ocean energy installations are as follows (in%): Civil works – 55; Mechanical and electrical equipment – 21%; Site preparation: 12%; Electrical transmission – 5%; Miscellaneous – 7%. Ocean energy projects are still in the development stage, and firm costs cannot be given. They are, however, in the range of USD 150/MWh to USD 300/MWh.

Investment and production costs of geothermal and ocean energy are given in Table 4.2.1.

4.3 WIND ENERGY[2]

4.3.1 Introduction

The incredible saga of Mr. Tulsi Tanti, a self-made Indian billionaire, symbolizes the phenomenal growth of wind energy globally. He started with two windmills to supply cheaper and reliable power for his textile mill in Pune, India. He never looked back after that. His company, Suzlon Energy, has operations in about 20 countries, and has 10% share of the world market. It is presently the fourth largest wind turbine maker in the world. Suzlon is investing USD 5 billion to provide 3500 MW of wind electricity to 10 million people in India and China.

Amongst the various sources of renewable energy, wind energy has the least number of hassles. Air which drives the wind turbine to produce power, is free, and is not scarce any where in the world. Wind power is economically viable in areas where the wind speed is 2.5–25 m/s. No wonder, wind power has grown 50 times since 1990

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[2] The Chapter on Wind Energy draws extensively from *Energy Technology Perspectives*, 2008, Chap. 10, Wind, pp. 339–363.

Table 4.3.1 Top ten countries in installed wind power capacity.

Country	*MW*	*%*
Germany	22,247	23.6
United States	16,818	17.9
Spain	15,145	16.1
India	8,000	8.5
China	6,050	6.4
Denmark	3,125	3.3
Italy	2,726	2.9
France	2,454	2.6
United Kingdom	2,389	2.5
Portugal	2,150	2.3
Rest of the world	13,018	13.8
Total top ten	81,104	86.2
Global total	94,122	

Source: *Energy Technology Perspectives*, 2008, p. 342.

to the global installed capacity of 94 GW in 2007. These are essentially onshore installations. Since 2001, installed wind capacity has been growing at the rate of 20–30% per year. The year 2007 saw the installation of 20 GW wind power capacity, worth USD 31 billion. The wind-generated electricity contribution to the national electricity is around 1% in ten countries, and about 17% in the case of Denmark.

There are wind farms in about 40 countries in the world, with thirteen of them having a capacity of 1000 MW of installed capacity. The top ten countries in the world in terms of installed wind power capacity are listed in Table 4.3.1.

4.3.2 Projected growth of wind power

ACT scenario:

From its current capacity of 94 GW, the global wind power capacity is projected to grow to 1360 GW by 2050 under the ACT scenario. Electricity production from wind power is projected to contribute 2712 TWh/yr by 2030 and 3607 TWh/yr by 2050.

BLUE scenario:

The BLUE scenario assumes profound technoeconomic improvements, in the form of higher CO_2 incentives, greater cost reductions, extensive offshore wind power development and improvements in innovative storage, grid design and management.

The BLUE scenario envisages the installation of 700,000 turbines of 4 MW size by 2050. Wind power installed capacity will go up to 2010 GW by 2050, with wind electricity generation of 2663 TWh/yr in 2030, and 5174 TWh/yr in 2050. Wind power contribution to global energy production will reach 12% by 2050, thereby reducing the CO_2 emissions by 2.14 Gt CO_2/yr. By 2050, China will be the world leader in wind power, with electricity from wind power accounting for 31% of the world production.

4.3.3 Technology and cost developments

Wind power technology has made great strides. Today's standard design is three-bladed, horizontal access, upwind and grid connected wind turbine. The capacity of the wind turbine increased from 50 kW in 1985 to 3600 kW in 2005, concomitantly with the increase in rotor diameter from 20 m to 120 m. The largest wind turbines presently in operation in the world have the capacity of 5–6 MW, with rotor diameter upto 126 m.

Installation costs of wind power range from USD 1224/kW in Denmark to USD 1707/KW in Canada. Turbine prices which constitute 75% of the total costs, increased by 20% since 2004. Operation & maintenance and miscellaneous costs range from USD 13/MWh to USD 24/MWh.

Water depth and distance from the coast determine the offshore wind power costs. United Kingdom established a 90 MW offshore wind turbines in 2006. The costs ranged from USD 2226/kW to USD 2969/kW. Offshore turbines cost about 20% more than the onshore turbines. Also, offshore towers and foundations cost 2.5 times more than similar structures on land.

4.3.4 Market overview

In 1980, Denmark and California were virtually the only markets in the world for wind turbines. The market collapsed in California when the financial incentives were withdrawn. Denmark survived by falling on the stable domestic market. In mid-1990's, Germany entered the market, followed by Spain. There has been a great boom in the wind power industry. Six leading turbine manufacturers account for 90% of the global market. The global top ten wind turbine manufacturers are listed in Table 4.3.2.

Three parameters determine the amount of power from wind turbine: wind conditions, turbine height, and efficiency of the turbine. While the wind regime of a site is a given, higher output of power can be realized by making the turbines larger and taller. Germany and Denmark increased the productivity of their prime sites by replacing the earlier-installed smaller and shorter turbines by larger and taller turbines. The efficiency of energy production is measured on the basis of annual energy production per unit of swept rotor area (kWh/m^2). The same parameter determines

Table 4.3.2 Global top ten wind-turbine manufacturers.

Manufacturer	*Capacity supplied in 2006 (MW)*	*Market share (%)*
VESTAS (Denmark)*	4,329	28.2
GAMESA (Spain)	2,346	15.6
GE WIND (USA)	2,326	15.5
ENERCON (Germany)	2,316	15.4
SUZLON (India)	1,157	7.7
SIEMENS (Denmark)	1,103	7.3
NORDEX (Germany)	505	3.4
REPOWER (Germany)	480	3.2
ACCIONA (Spain)	426	2.8
GOLDWIND (China)	416	2.8
Others	689	2.6
Total	16,003	

Source: BTM Consult, 2007.

* Country designation refers to the corporate base.

the manufacturing costs. The trend is therefore towards larger and taller and more efficient wind turbines. The efficiency of the wind power sector has increased by 2–3% annually during the last 15 years through better turbine siting, more efficient equipment and higher hub heights.

The cost of the turbine constitutes 74–82% of the capital costs of the medium-sized onshore power stations (i.e. 850 kW to 1500 kW). Other costs are as follows:

Foundations: 1–6%; Electric installation: 1–9%; Grid connection: 2–9%; Consultancy: 1–3%; Land: 1–3%; Financial costs: 1–5%; Road construction: 1–5%.

The onshore wind power production costs depend upon the wind conditions. They range from low costs (US cents 8.9/kWh) at sites of high wind speeds (such as coastal areas), and high costs (about US cents 13.5/kWh) at sites of low wind speeds (such as, inland areas). As the cumulative capacity is likely to double every three years, the costs are projected to decline by 2015 to US Cents 5.3/kWh at high-wind sites and US Cents 6.3/kWh at medium-wind sites.

Operation & Maintenance costs average 20–25% of the total cost per kWh produced. They tend to be low (10–15%) in the early years of the turbine, and may rise to 20–35% in the later years. To bring down O & M costs, manufacturers are developing new turbine designs that have less down time and require fewer service visits. Experience in Europe suggests O & M costs of US cents 1.5/kWh to 1.9/kWh of the produced wind power over the life time of the turbine.

Wind power is more capital intensive (capital costs account for 75–80% of the production costs) relative to fossil fuel power stations (where the corresponding figure is 40–60%).

4.3.5 Environmental factors

The plus point of the wind power is that it has no carbon dioxide emissions. Wind power has three environmental impacts: visual impact. noise, risk of bird collisions and disruption of wild life. As the wind turbines could be seen from long distance, some object to them as being obtrusive. Some companies developed photo-montage and animation tools to mitigate the problem. Two kinds of noises are associated with wind turbines: aerodynamic noise from the blades, and mechanical noise from the rotating machinery. Design improvements are bringing about a sharp reduction in the noise. The risk to migratory birds could be avoided by siting the wind farms where the routes of the migratory birds do not cross.

Denmark which made extensive studies on the behavioral response of the marine mammals and birds to offshore wind farms, has developed guide-lines for minimizing impact of offshore wind farms on marine biota. These could be applied to estuarine and open sea sites of offshore wind stations.

4.3.6 Offshore wind power

4.3.6.1 General considerations

Presently, most of the wind power is generated by land-based wind turbines. Offshore wind installations are 50% more expensive than land-based wind installations. Still companies are going in for offshore wind power because the output of offshore installations is 50% more than onshore installations, due to better wind conditions.

Offshore wind power installations have to operate "under harsh conditions, shortage of installation vessels, competition with other marine users, environmental impacts and grid interconnection" (*Energy Technology Perspectives*, 2008, p. 352).

Five countries (Denmark, Ireland, Netherlands, Sweden, and U.K.) have established offshore wind power stations with a total capacity of 1100 MW. Most of these installations (typically 2 MW capacity) are sited in relatively shallow water (<20 m deep) and close to the coast (<20 km). U.K. is establishing a large (~1000 MW) facility situated more than 20 km offshore. When completed in 2009, it will be capable of providing power to one-quarter of the households in London.

4.3.6.2 Investment costs

As should be expected, the capital costs of the offshore power stations are dependent upon wind speeds, water depth, wave conditions and distance from the coast. The experience in U.K. is that the costs range from USD 2 225–2 970/kW. The higher capital cost of the offshore wind installations is partly offset by the lower costs of production of the offshore wind electricity. This is so because the offshore installations are exposed to higher wind speeds for longer periods (i.e. 3000–3300 full load-hours per year, or ~34% capacity factor) relative to the onshore installations (2000–2300 full load hours per year, or ~25% capacity factor). Danish wind farms have recorded high load hours of 3500–4000 hours per year.

Investment costs vary from USD 1.5 million to 3.4 million/MW, depending upon water depth and distance from the coast. Foundations and grid connections account for the difference in costs between onshore and offshore wind power.

The break-down in the offshore wind power investments costs is given in Table 4.3.3.

Annual Operation & Maintenance costs are in the region of USD 20/MWh, averaged over the lifetime of the turbine, normal operating conditions and discount rate of 7.5%.

Steel which is used for the construction of the turbine, accounts for 90% of the cost of the turbine. Turbine fabrication costs can be brought down if steel could be replaced by a lighter and more reliable material, and if the fatigue resistance of the gear boxes can be improved.

Table 4.3.3 Offshore wind power investment costs.

	Investment costs USD 1000/MW	*Share %*
Turbines, exwork, Including transport and erection	1,020	49
Transformer station and main cable to coast	340	16
Internal grid between turbines	105	5
Foundations	440	21
Design, project management	125	6
Environmental analysis	75	3
Miscellaneous	12	<1
Total	2,117	

Source: Lemming et al., 2007.

Table 4.3.4 Estimated offshore wind turbine costs during 2006–2050.

Year	*Average investment costs (million USD/MW)*	*O&M (USD/MWh)*	*Capacity factor (%)*
2006	2.6	20	37.5
2015	2.3	16	37.5
2020	2.0	15	37.5
2030	1.8	15	37.5
2050	1.7	15	37.5

Source: Lemming et al., 2007.

Estimated offshore wind turbine costs during 2006–2050 are given in Table 4.3.4. Offshore wind power will be progressively cheaper.

4.3.6.3 Further technology development

The European Union has launched an impressive wind energy R&D initiative, code named UpWind, aimed at developing very large turbines (8 to 10 MW) and large wind farms of several hundred megawatt capacity. The programme would involve better understanding of wind conditions, development of materials with high strength to mass ratios, and improved control and measuring systems.

Some innovative approaches in this regard are described below:

Superconducting generators: Denmark Technical University, Risø, is developing a 10 MW generator which achieves 50–60% reduction in weight through the use of high-temperature, superconducting materials. By making direct drive possible, it avoids the use of gear-boxes, and thus brings down O&M costs.

Compressed air energy storage (CAES): When the demand is low, wind electricity is used to compress air, which is then stored in a geological formation, say, salt domes. When the demand rises, the flow is reversed. The compressed gas is fed into natural gas-fired turbine, thereby enhancing its efficiency by more than 60%.

Floating platforms: As in the case of oil industry, platforms are built on land and towed to sea. Wind turbines are mounted on these platforms.

Hybrid systems: In the Poseidon's Organ arrangement, a floating offshore wave power plant also serves as a foundation for wind turbine.

System aspects: Traditionally, electricity grids and power markets link large-scale electricity producers with consumers. Wind power does not conform to this pattern. In 2006, wind energy provided 17% of Denmark's electricity demand. This was possible because the Danish wind power could export surplus power to, and import electricity from, the Nordic Power market. The moral of the story is that dispersed wind power plants needs to be aggregated, and linked to power markets in such a way that short falls cost the least.

IEA is developing a strategic plan on the wind power, on the basis of the identification of R&D priorities (Table 4.3.5).

Table 4.3.5 R&D in regard to wind energy systems.

Task	*Objective*
Base technology information exchange	Further development of wind energy conversion systems through cooperative action and information exchange
Wind energy in cold climates	Gather and share information on wind turbines operating in cold climates
Horizontal axis wind turbines	Compare theoretical aerodynamic model predictions of wind turbine blade and structural performance and load with actual measurements
Dynamic models of wind farms in power systems	Address effects on power systems of interconnecting and operating large number of wind turbines
Offshore wind energy technology development	Address relevant issues of offshore wind development, including deployment in deep water
Integration of wind and hydropower systems	Conduct cooperative research concerning the generation, transmission and economics of integrating wind and hydropower systems; provide a forum for information exchange
Design and operation of power systems with large amounts of wind	Investigate impacts of variable wind power on power system operation
Cost of wind energy	Assess methodologies for estimating cost of energy and establish a method of assessing its impact on R&D.

Source: *Energy Technology Perspectives*, 2008, p. 360.

4.4 BIOMASS AND BIOENERGY

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4.4.1 Introduction

Renewables figure prominently in the energy economy of Brazil. According to "Renewables Information, 2008", Brazil has 96.4 Mtoe (million tonnes of oil equivalent) of Renewable Energy, out of which combustible renewables and wastes account for 66.4 Mtoe.

Biomass can be virtually obtained from any living or recently dead organic matter that can be used as a source of energy into a number of processes. Following the classification of the International Energy Agency (IEA), biomass is a renewable energy resource that includes various sources that can be grouped into renewable combustibles and renewable waste. Some of these renewable combustibles and their converted technology are illustrated by the World Business Council for Sustainable Development in Figure 4.4.1.

Even this definition does not give immediately the perception that biomass encompasses a myriad of resources. Biomass resources include agricultural and forestry residues, municipal solid wastes and industrial wastes. Amongst them one can find charcoal, renewable landfill gases, solid and liquid biomass, the so called biofuels such as ethanol and biodiesel.

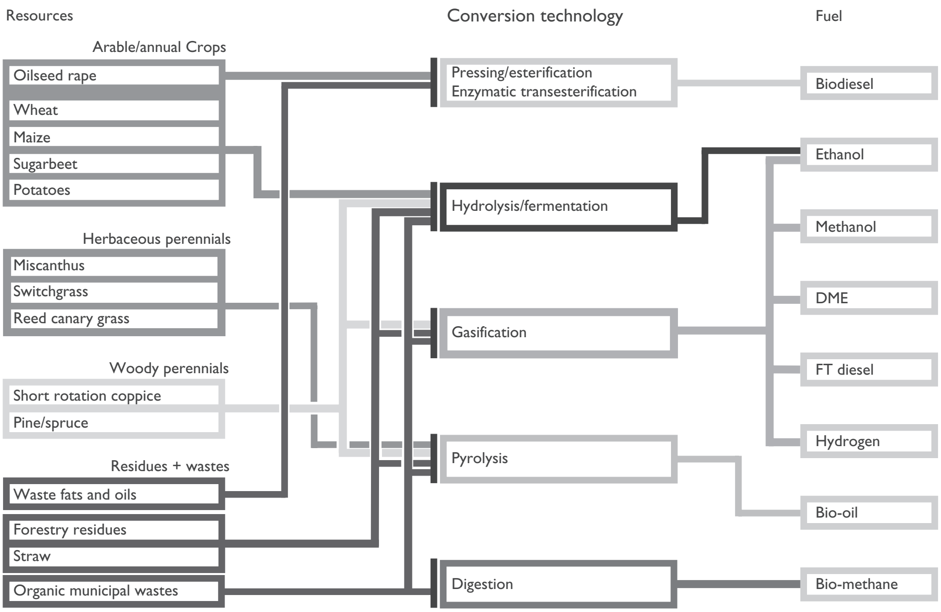

Figure 4.4.1 Renewable combustibles: Biofuels pathways.

Source: World Business Council for Sustainable Development, 2008.

Biodiesel, for its turn, can be originated from left-over food products like animal fats and vegetable oils from many terrestrial and aquatic crops, some of them grown solely for energy purposes. Algae, for example, has been showing large potential, although much research is being required to cultivating specific algal strains appropriate for biofuel production.

Biodiesel also is primarily produced through catalyzed transesterification. It is considered simple to use combustible besides being biodegradable, nontoxic and essentially free of aromatics and sulfur. Biodiesel can also be blended at any level with petroleum diesel without requiring any specific technology for this purpose.

Biomass as an energy resource presents a profound regional difference in its use. While the biomass share in the energy mix of developed countries is situated around 3–4%, in regions like Africa this figure may represent 70–90% of the total African energy demand.

Another peculiar feature of biomass is that there is a clear boundary between its *traditional* and its *modern* form. While *modern biomass* is associated with high technological contents and large scale of biomass production, *traditional biomass* is used inefficiently and not obtained through a sustainable fashion. Thus traditional biomass is frequently related with poverty, lack of access to other resources of energy for domestic cooking and space heating.

Traditional biomass keeps a close relation with poverty indicators (Table 4.4.1) and lack of means to access more efficient and healthier forms of energy. In fact systematic inhalation of particulates and unhealthy gases originating from the use of traditional

Table 4.4.1 Biomass use and demographic indicators.

Use of traditional biomass in %	*0–20*	*20–40*	*40–60*	*60–80*	*Above 80*
Number of countries	70	12	14	10	16
Female life expectancy (years)	74.70	68.80	62.00	56.1	48.30
Life expectancy (years)	71.50	66.50	59.90	51.50	47.00
Male life expectancy (years)	68.50	64.00	57.80	53.00	45.80
Infant mortality (per 1,000 live births)	22.50	46.6	64.70	92.60	116.80
Under–five mortality (per 1,000 live births)	27.50	59.30	93.00	135.30	173.00
Total fertility rate	2.51	3.26	4.64	5.35	6.33
Crude birth rate	19.20	26.20	35.00	39.10	45.00
Crude death rate	8.60	7.60	10.90	12.80	18.10
Annual population growth rate (%)	1.00	1.61	2.43	2.74	2.52
Female–male life expectancy gap (years)	6.20	4.50	4.20	3.10	2.60

Source: United Nations, WEA, 2004.

biomass in household cooking or heating plays a major role in lowering the standards of living in less developed countries.

In the category of modern biomass, for its turn, there are multiple energy resources. They include ethanol, black liquor from pulp and paper manufacturing, planted wood and soybean oil, among others (IPCC, 2001). Although it can also encompass biodegradable wastes that can be directed to power generation, the most relevant destination of modern biomass, considering the scale of processes and total amount energy output, is its use as biofuel for transportation.

Although biomass is the world oldest form of renewable energy its use has declined with advent of fossil fuels. Nevertheless it represents the largest share of renewable energy nowadays. In 2006, 12.7% Total Primary Energy Supply or 1493 Mtoe was originated from renewable energy sources – biomass, hydropower, wind, solar, geothermal and tide, mainly. Biomass – combustible renewables and waste – represented almost 80%, or more precisely 78.1% of the total renewable share from the Total Primary Energy Supply, equivalent to 1,166 Mtoe, according to IEA figures for 2006.

Biomass also projects the highest technical potential among all renewable energies. If IEA projections became true, biomass use may triple by 2050, reaching 150 EJ/yr or 3604 Mtoe/yr. It is estimated that the amount of energy supplied through biomass may require the delivery of 15,000 Mt of biomass to production plants annually. Half of this figure is expected to come from purpose-grown energy crops, and the other half is expected to coming from residues of crops and forests.

Although biomass presents the highest technical potential among all renewables, its share relative to other renewable energy sources is expected to decline. This decrease comes from the fact that comparatively wind and solar energy have shown higher growth rates. For instance, the use of biomass for power generation is expected to triple by 2030, while energy from wind is expected to increase 17-fold, leading to similar generation capacities around that year (Figure 4.4.2).

For generating electricity and power, biomass from agriculture and forestry residues, as well as residues from paper mills are amongst the most common resources used. Other uses of biomass include industrial process to generate heat and steam.

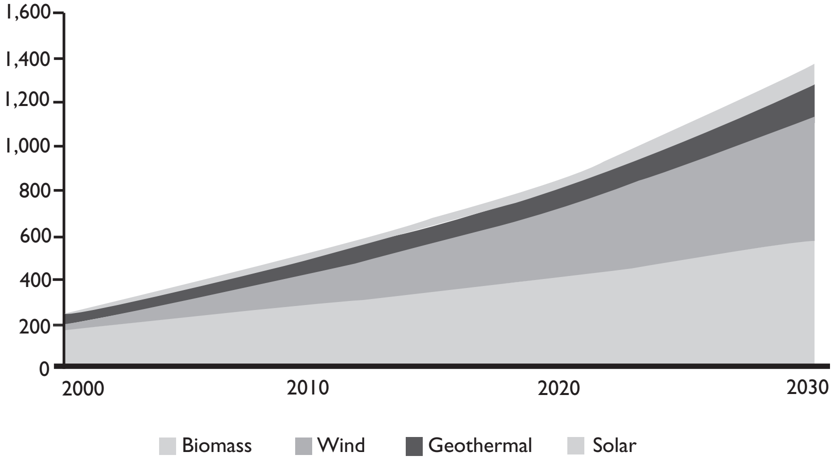

Figure 4.4.2 Evolution of renewables (See colour plate 14).

Source: United Nations, WEA, 2006.

For transportation, liquid fuels such as ethanol and biodiesel, derived primarily from agricultural crops, are increasingly significant.

Grain crops such as soybeans are amongst the agricultural products specifically grown for conversion to biofuels. New research is being conducted to improve the conversion of non-grain crops, such as some woody crops and switchgrass into biofuels.

One major potential opportunity for this kind of synergy is the replacement of fossil fuels by biofuels for transport. This replacement has been promoted in many countries for reasons such as reducing import dependency, reducing price volatility and local environmental improvement, but they also bring large potential climate advantages. Brazil has for several decades been at the forefront of introducing these fuels, and is an ideal place to look for lessons that can be applied elsewhere. The next section of this chapter analyses some of the Brazilian experience that might be usefully applied elsewhere.

4.4.2 The Brazilian experience with ethanol

This Section draws from the earlier works (*Ethanol: evaluating pros and cons of the recent Brazilian experience*, by Parente and Moreira, 2008) and the publication for the World Resources Institute (*Biofuels for transport, development and climate change,* by Moreira, Nogueira and Parente, 2005).

Ethanol has been used as a fuel since the beginning of automobile use in Brazil. In fact, in 1903 a national meeting on applications of ethanol put forward plans to develop an infrastructure to produce and distribute ethanol from sugarcane as motor fuel. During World War I, the use of ethanol was compulsory in many areas of the country. By 1923, production of ethanol had grown to 150 million liters per year and in 1927 it was blended with diethyl (ethyl) ether and castor oil. A Federal Decree, in 1931, established the compulsory addition of 5% of ethanol in gasoline, value

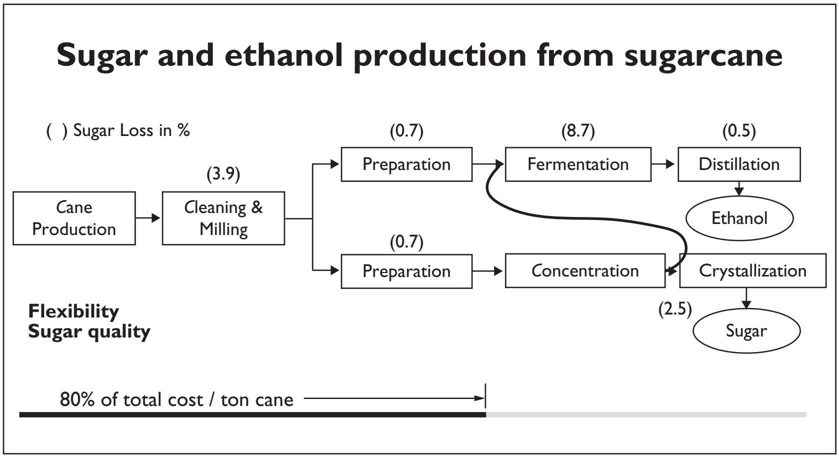

Figure 4.4.3 Simplified flow diagram for sugar and ethanol production from sugarcane.

Source: Macedo et al., 2004.

elevated to 10% in 1966. By 1941, the total production of ethanol in the country reached 650 million liters.

In most of the Brazilian territory ethanol has been largely used as an alternative for gasoline for the automobile fleet. All ethanol in the country has been produced solely from sugarcane through the fermentation of sugars contained in the sugarcane juice. Thus the same agricultural product can be used to produce either sugar or ethanol (Figure 4.4.3). The market for ethanol is therefore intimately interlinked with that for sugar and related products, and the history of ethanol needs to be understood with this in mind.

Sugarcane is grown in more than 100 countries worldwide, and accounts for the majority of global sugar production. Brazil plants and harvests a large amount of sugarcane (about 400 million tons in the 2004/5 growing season). Aside from sugar and ethanol, products from the cane include biodegradable plastics and low-grade paper. The byproducts, bagasse (residues from the sugar manufacturing process) and barbojo (tops and leaves remaining from harvesting) are generally burned. Bagasse, in particular, is traditionally used as a source of heat and electricity for the agroindustries processing sugarcane into ethanol and sugar.

Nearly half of Brazil's cane is destined for ethanol. Brazil has two distinct sugar producing regions. The Southern-Central region is dominated by the state of São Paulo, which alone accounts for 65 percent of the country's sugarcane production. This region supplies three-quarters of the country's cane, over 70 percent of the sugar output, and approximately 90 percent of the ethanol. The Northeast accounts for less than 20 percent of Brazil's sugarcane production, approximately 25 to 30 percent of the country's sugar output, and about 10 percent of its ethanol.

Table 4.4.2 summarizes major indicators of the sugar/ethanol sector in Brazil for the year 2005. Raw and refined sugar account for roughly 2–4% of Brazil's exports, depending on yields. The beginning of large utilization of ethanol as fuel for vehicles in Brazil dates from 1931. For the period that goes from 1931 to 1975, around 7%

Table 4.4.2 The Sugar/Ethanol Sector – Brazil, 2005.

A US$ 20 billion annual market	
Gross Turnover	US$ 20 billion
Share of National Income	3.6% of GNP
Employment	3.7 million jobs
Sugarcane growers	70,200 farmers
Sugarcane harvest	370 million tons of sugarcane
Output – Sugar	26 million tons of sugar
Output – Ethanol	20 billion liters of alcohol
Exports – Sugar	15.5 million tones of sugar
Exports – Ethanol	750 million liters of alcohol
Taxes	US$ 1.8 billion
Investments	US$ 1.5 billion/year
Participants	306 mills

Source: MME and Unica, 2007.

the total Brazilian gasoline consumption was substituted by ethanol, as established by law. In 1975 the Brazilian Alcohol Program was launched, increasing the use of gasohol and promoting pure ethanol utilization in dedicated models. Figure 4.4.4 shows the evolution of alcohol production since then.

Examining in detail the alcohol program in Brazil it is evident that substantial cost reductions were obtained after 1999. The increase in productivity plus the uptrend in the cost of oil since 2000, has rejuvenated the Brazilian ethanol program. The number of new automobiles running on hydrous ethanol, which had almost come to zero in the period 1995–2000, started to show significant improvement from 2000 to 2008.

The coupled production of alcohol and sugar can be seen as a significant driver for the successful alcohol program in Brazil. The steps involved in sugar and alcohol productions from sugarcane, as shown in Figure 4.4.4, allow flexibility of production. If sugar production becomes less attractive due to reduced prices in the international market, it might become more profitable to shift production to alcohol. In common with many agricultural commodities, international sugar prices have been both highly volatile and on a general downward trend.

Another important area of synergy regarding the sugar cane production, which is still being fully realized, is in associated electric energy production. The energy content of sugarcane residues at world level has been evaluated as 7.7 EJ per year (Hall et al, 1993). Updating this figure using crop area and yield data for 2004 (FAO, 2005), we calculate that the energy content of such residues today is 12.48 EJ/yr.

Capturing this energy for electricity generation and heat production is an important contributor to the success of biofuels. At present, cogeneration of heat and electricity from bagasse residues covers most of the energy needs of the biofuel production process itself, as well as allows an increasing amount of electricity to be exported to the grid.

Yet the main importance of the Brazilian ethanol program is the replacement of gasoline by another fuel, which has been a challenge in several countries due to a myriad of aspects. One of these aspects has to do with "a chicken and egg problem" in the supply chain. Consumers are afraid of buying cars that use any new fuel due to difficulties in finding the new fuel around the large area that an automobile is designed to

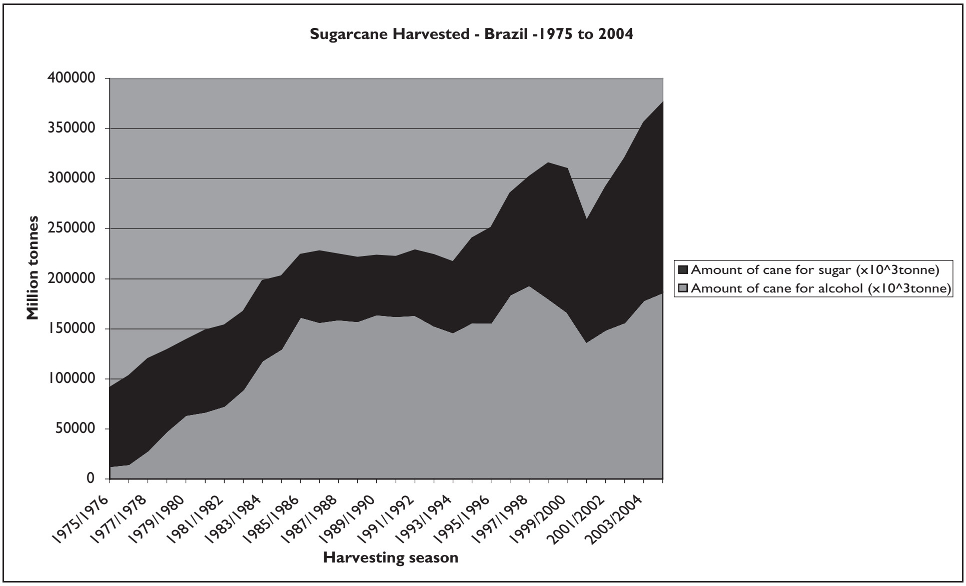

Figure 4.4.4 Sugarcane harvested for production of sugar and alcohol.

Source: MME, Unica, 2006.

move. Service stations' owners are not interested in investing in a parallel fuel supply distribution system since the number of potential users is usually very small.

In this context the leadership role of the Brazilian government at both Federal and State level, in providing the incentives and a clear institutional framework, was absolutely essential. This role included the setting of technical standards, support for the technologies involved in ethanol production and use, financial advantages and market conditions.

The data regarding the energy balance of Brazilian biofuels programs are in principle neutral in terms of CO_2 emissions. Even though planting, transporting and transforming energy crops to biofuels uses external energy, usually derived from fossil fuels, a life cycle assessments have shown a neutral balance regarding the net effect on greenhouse gases emissions.

4.4.2.1 Carbon emission abatement

An additional climate benefit comes from the export of surplus biomass-generated electricity to the grid. The 60 kWh of electricity that can be generated from a ton of sugarcane would replace 0.65 GJ of fuel oil (assuming 33% conversion efficiency to electricity). This represents 52.3 GJ/ha (for a yield of 80tcane/ha/yr) abating 4.04tCO_{2eq}/ha/yr. There is considerable scope for improving this performance. Improved technology can raise the electricity production from 60 kWh per ton to 500 kWh per ton (MME, 2006).

The set of incentives has changed significantly over the lifetime of the ethanol program. In the 1970s the government controlled the fuel market through its state-owned oil company Petrobras, which had the monopoly of ethanol distribution. The government's role receded gradually, and this monopoly ended in the late 1990s. The government's remaining participation, according to Presidential Decree, regulates the level of ethanol to be blended into gasoline.

Since the 1970s many countries started to put ethanol programs in place. Brazil and USA were outstanding in that practice. Also Argentina, Paraguay, and Zimbabwe had launched important programs. As oil prices dropped, government support waned and, by the end of the last century, only Brazil and USA still maintained those programs. The programs in Argentina, Paraguay and Zimbabwe were too small to survive when oil prices declined in the early 80s. However, China, India, Colombia, Thailand, and Australia have started their own programs which may trigger large scale uses of ethanol worldwide. The Brazilian experience demonstrates that it is possible to quadruple sugarcane production in less than a decade and that public acceptance for a new liquid fuel can be secured through appropriate government policies.

4.5 SOLAR ENERGY[3]

4.5.1 Introduction

Sun is worshipped in all cultures as the embodiment of energy. Solar energy falling on earth is so vast that sunlight falling on earth for one hour would be enough to supply energy to the whole world for one year. Its use is, however, limited by its low energy intensity and intermittency. Solar energy currently accounts for 1% world's commercial energy. Both industrialized and developing countries stand to gain by it.

Solar energy can be used in the following ways: (i) Direct supply of solar heat to buildings and industrial processes – provision of heat accounts for about 40% of the global energy needs, (ii) electricity can be produced through the photovoltaic cells, or through steam turbines by the concentration of solar rays, and (iii) production of hydrogen which can be used as fuel. Among all the energy systems, solar energy is projected to grow the fastest. Between now and 2050, solar energy is expected to grow thousand-fold, to 2319 TWh/yr in the ACT scenario, and 4754 TWh/yr in the BLUE scenario. It is assumed that during the next ten years, there will be sustained support to the solar energy sector to enable it to become competitive. Under both ACT and BLUE scenarios, major growth is likely to occur after 2030. PV is expected to grow fast in the solar-rich OECD countries (e.g. North America) and the emerging economies of China and India. CSP (Concentrated Solar Power) will grow strongly not only in these countries, but also in the sun belts of Africa and Latin America.

4.5.2 Photovoltaics

A photovoltaic cell (PV cell) is a semiconductor device that is capable of converting solar energy into direct current (DC) electrical energy. A PV cell is typically a low voltage (~0.5 V) and high current (~3 A) device. PV modules are built by combining

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[3] This chapter draws extensively from *Energy technology perspectives*, 2008, pp. 365–386.

a number of PV cells in series. A commercial module with an area of 0.4 m^2 to 1.0 m^2 can produce peak power of 50 Wp (peak Watts) to 150 Wp. By linking together appropriately large number of PV cells, it is possible to build huge power units with a capacity of tens of MWs.

In mid-1990s, stand-alone, off-grid PV systems were common, as they are most economically viable for use in rural areas. Water pumping and rural electrification continue to account for about 10% of the PV market. Subsequently, grid-connected systems, particularly those that are integrated into building design, have come into vogue in a big way. Since 2000, the total cumulative PV capacity in the world has grown eight-fold to 6.6 GW, 90% of which is composed of grid-connected systems.

Distributed generation in buildings account for 93% of the grid-connected systems.

Germany, Japan and USA account for 63% of the global PV production. China, India, Australia, Korea and Spain are expanding their PV installed capacity and manufacturing capability. China already accounts for 15% of the global production of PV cells. Japanese companies (Sharp, 17.1%), Kyocera (7.1%), Sanyo (6.1%) lead the world in PV manufacturing capacity, followed by Q-Cells (10%) of Germany and Suntech (6.3%) of China. The shortage of purified silicon is expected to ease in 2008.

Several plants are fabricating hundreds of megawatts of PV modules yearly. Japan is planning to build one GW manufacturing plant.

By 2010, ACT map scenario projects a market of 6 GW/yr and the BLUE map scenario projects a market of 10 GW/yr. The industry envisages a much higher annual production of 23 GW/yr of PV cells/modules by 2011. By 2050, the annual power generation from PV is expected to reach 1 383 TWh/yr as per ACT scenario and 2 584 as per BLUE scenario (the latter figure would correspond to 6% of the global production of electricity in 2050).

4.5.3 PV technology

Wafer-based crystalline silicon (c-Si) is the basic material for the fabrication of most (~90%) of the PV modules. After oxygen, silicon is the most abundant element in the earth's crust, but because of its great affinity for oxygen, silicon always occurs as silica (SiO_2). The value of one kg. of quartzite gets increased 65 million times when it is made into computer chips, through the following steps:

1 Quartzite ($0.02/kg) to metallic silicon ($2/kg) – 100 times increase in value
2 Metallic silica ($2/kg) to polysilicon ($40/kg) – 20 times increase in value
3 Polysilicon ($40/kg) to silicon wafer ($1500/kg) – 37 times increase in value
4 Cutting the wafer ($1500/kg) into chips ($1.3 million) – 860 times increase in value

Ingots of silicon (which are made from silica) are sliced to make solar cells, which are then electrically inter-connected. A module is fabricated by encapsulating strings of cells. The module built of single crystalline silica (sc-Si) tends to have a higher conversion efficiency, which is presently 15% now but is expected to increase to 25–28% by 2050. A module can be made from multi-crystalline silica (mc-Si), but such a module, though cheaper than sc-Si, has lower conversion efficiency. Ribbon technologies have conversion efficiencies similar to those of mc-Si, but make use of silicon feedstock more efficiently.

About 40% of the Indians have no access to electricity – they use kerosene wick lamps for lighting. These lamps give poor quality light, emit unhealthy fumes and constitute a fire hazard in thatched houses in which poor people live. As a substitute for the kerosene lamp, D.T. Barki's NEST (Nobal Energy Solar Technologies), Hyderbad, India, has successfully developed and is marketing in developing countries, an inexpensive (about USD 30, which can be paid for in 16 monthly installments of USD 2 each), portable and sturdy solar lantern which gives three hours of good light. The battery has a life of three years, and solar panel has a life of ten years. The solar lantern is a good example of globalization – it is fabricated in China, with silicon feedstock from Japan, and marketed from India.

4.5.3.1 Thin films

Thin film technology is rapidly emerging as a viable alternative to silicon wafer technology. A thin layer of photosensitive material is deposited on a low-cost backing, such as, glass, stainless steel or plastic. Initially, amorphous silicon (α-Si) was used, but now-a-days, Cadmium Telluride (CdTe) or Copper-Indium-Diselenide (CIS) are used instead. The efficiency of CIS gets improved when it is doped with gallium, to produce a CIGS module. The thickness of the thin film may range from 40–60 μm in the case of c-Si to less than 10 μm in the case of CdTe.

Thin films use smaller quantities of feedstock, and are amenable to automation. They can be integrated into buildings more readily and have better appearance. Their efficiencies are, however, lower than c-Si modules. Recent improvements in CIS modules have allowed them to have efficiencies of the order of 11%, which figure is comparable to the efficiency of mc-Si modules. An efficiency of 22% is projected for CIS modules by 2030. But the availability of Cd and Te may prove to be a constraint. Thin films are likely to increase their market share by 2020. After that, hybrid systems which combine crystalline and thin-film technologies, may dominate the market. These hybrid systems have the best of both the worlds – higher efficiencies of the order of 18%, lower material consumption and amenability to automation.

The module efficiencies of different PV systems are summarized in Table 4.5.1.

The consensus in the PV industry is that after 2020, the market share of c-Si PV systems will decrease, and that thin-film technology will dominate the market. Two types of Third generation PV devices are expected to come up during 2020–2030:

Table 4.5.1 Present module efficiencies for different PV technologies.

	Wafer-based c-Si		*Thin films*		
	Sc–Si	*mc-Si*	*α-Si,* *α-Si/mc-Si*	*CdTe*	*CIS/CIGS*
Commercial module efficiency (%)	13–15	12–14	6–8	8–10	10–11
Maximum recorded module efficiency (%)	22.7	15.3	–	10.5	12.1
Maximum recorded laboratory efficiency (%)	24.7	19.8	12.7	16.0	18.2

Source: Frankl, Manichetti and Raugei, 2008.

Table 4.5.2 Technology and market characterization of different PV technologies in 2050.

	Wafer-based c-Si		*Thin films*		*New concept devices*	
	Cz, Fz	*mc, ribbon*	*CIS, Cd-Te, α-Si/μc-Si thin Si films*	*Pin-Asi and ASI-THRU*	*Ultra-high efficiency (3rd generation, quantum wells nanostructures concentrators*	*Ultra-low cost (dye-sensitized cells, organic cells)*
Module efficiency (%)	**24%–28%**	**20%–25%**	**CIS: 22–25% Si: 20%**	**6%–8%**	**>40%**	**10%–17%**
Module lifetime (years)	40–50 years	40–50 years	30–35 years	30 years	>25 years	10–15 years
Provided service	High pressure at premium price	Cost-effective Power applications	Additional solutions for cost-effective power applications	Low-cost, low-efficiency "solar electricity glass"	High power supply	Colour to PV low-material cost option
Market segment	Niche markets, space	Mass market ("The PV work horse")	Mass market	Mass market	Niche market/ mass market	Mass market
Applications	All applications with surface constraints (e.g. specific BIPV), ground – mounted Very large-scale PV	All	All special added value in BIPV (semi-transparwency, screen-printing, etc.)	Consumer products special applications large surface buildings	All applications with surface constraints; Ground-mounted, very large-scale PV	All

Source: *Energy Technology Perspectives*, 2008, p. 374.

i Ultra-low cost, low to medium efficiency cells and modules, such as dye-sensitized nanocrystalline solar cells (DSC) which could attain an efficiency of 10%, if not 15%, by 2030. Organic solar cells with efficiencies of the order of 2% are being developed. It is too early to speculate on their economic viability. They may figure in applications where space is not a problem.
ii Ultra-high efficiency cells and modules, based on advanced solid-state physics principles, such as, hot electrons, multiple quantum wells, intermediate band gap structures and nanostructures. It is difficult at this stage to predict their efficiency levels, but some experts predict that these devices may attain efficiencies of 30–60%.

Most likely, several types of PV devices may coexist in 2050. They are listed in Table 4.5.2.

4.5.3.2 Costs

As PV systems have no moving parts, Operation and Maintenance costs are minimal, at around 0.5% of the capital investment per year.

Presently, PV modules cost about 60% of the total PV system costs. Costs of mounting structures, inverters, cabling, etc. account for the rest of the 40%. PV costs are characterized by a high learning rate of 15–20% (learning rate means reduction in cost per each doubling of cumulative installed capacity). The cost of total PV systems was USD 6.25/W in 2006. A sustained high learning rate, and increased integration in buildings are expected to bring down the total PV investment costs to USD 2.2/W in 2030, and USD 1.24/W by 2050 under the ACT scenario. Under the BLUE map scenario, the corresponding figures would be USD 1.9/W in 2030 and USD 1.07/W in 2050.

The cost of electricity generated from PV systems depends upon the total solar irradiation, system lifetime (typically, 35 years) and the discount rate assumed (typically, 10%). It is expected to be in the range of US Cents 5/kWh to US Cents 7/kWh under conditions of good irradiation (>1600 kWh/kWp * yr).

4.5.3.3 R&D needed

c-Si module technology has been successful as it is reliable, takes advantage of the electronics industry, with ready availability of feedstock. Further advances that are needed in order for PV systems to reach large production volumes and low target cost of USD 1.25/W, are summarized below (PV-TRAC, 2005; EUPVPLATF (2007):

c-Si technology

i Materials: Epitaxial deposition; substitution of silver (because of cost) and lead (because of its health impact),
ii Equipment: Manufacturing processes (including ribbons) that use less silicon and less energy per watt. High degree of automation.
iii Device concepts and processes: Design of new modules which can be assembled more easily, low-cost and longer life span (25–40 years).

Thin film technologies

- i Materials and devices: Increase of module efficiencies from the current 5% to 15% or more; development of new multi-junction structures; reduced materials consumption; alternative module concepts, such as, new substrates and encapsulation modalities; enhancement of the module life for 20 to 30 years, with less than 10% reduction in efficiency.
- ii Processes and equipment: Techniques of ensuring uniformity of film properties over large areas, and bridge the efficiency gap between laboratory modules and large-scale industrial modules; reduction in the pay-back time of the modules from the present 1.5 years to 0.5 years.

4.5.3.4 New concept PV devices

Fundamental research in physics, chemistry and materials is needed to develop and operationalise these devices. The organically sensitized cells and modules need to have their stability enhanced to about ten years, with improvements in efficiency from 5% to 10%. The inorganically sensitized cells which are characterized by very low efficiencies, need to have their efficiency increased to 5–10%. The efficiency of very low-cost nano-structured devices needs to be improved to 5–10%. Two improvements are needed in the case of polymer and molecular solar cells: improvement in the efficiency from the present 3–5% to about 10%, and greater stability period (upto, say, ten years). Devices based on concepts for super-high efficiency and full-spectrum utilization, are being developed.

4.5.4 Concentrated Solar Power (CSP)

4.5.4.1 General considerations

Concentrated Solar Power (CSP) systems concentrate direct sunlight to reach high temperatures. This heat can then be used to power a steam turbine which drives a generator. CSP is best suited to areas with high direct solar radiation, the minimum requirement being 2 000 kWh/m^2. Figure 4.5.1 (source: Pharabad and Philibert, 1991) shows the most promising areas in the world suitable for CSP plants.

Unlike c-Si systems in which solar energy is directly converted to electrical energy, CSP system has thermal energy as an intermediate phase. In other words, it can store heat in various forms, and release power as and when needed. CSP can be used for continuous solar-only generation. Also it can burn fuel in hybrid plants and use the traditional steam turbines to generate power.

A strong plus point in favour of CSP is that it reaches peak production (at noon) exactly at the time when the electricity demand is at its highest (say, for air-conditioners) in tropical, arid and semi-arid areas. In these areas, CSP electricity is much cheaper than PV electricity, though it is costlier than fossil fuels and wind power.

As CSP plants are invariably large (typically several hundred megawatts), they have to be linked to transmission networks. For instance, it is possible to export CSP electricity from North Africa to Europe at the cost of USD 30/MWh – this figure is less than the cost difference in solar electricity between the two regions (DLR, 2006).

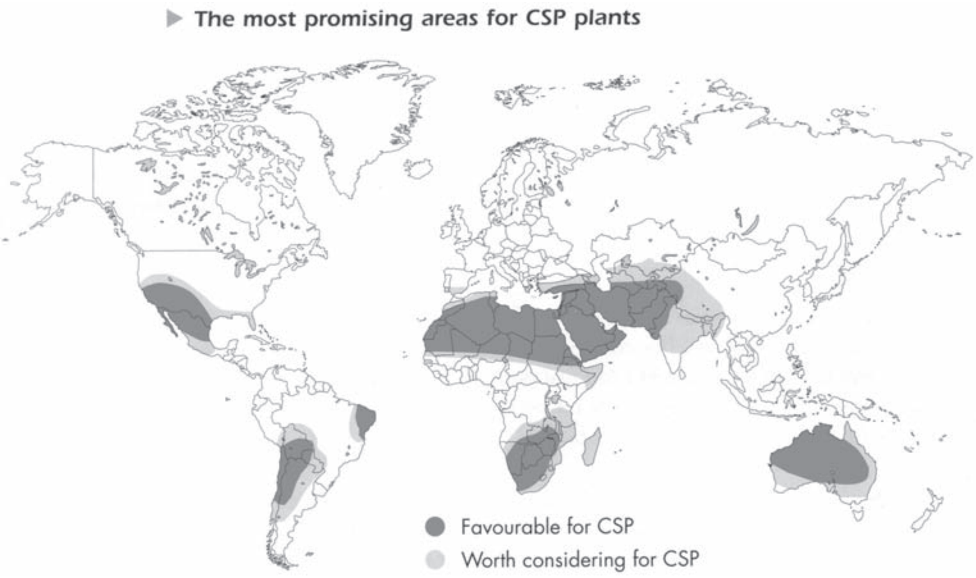

Figure 4.5.1 Map showing the most promising areas in the world suitable for CSP plants.

Key point: CSP use is best suited for high irradiative areas.

Source: Pharabad and Philibert, 1991.

Barring some special situations, space should not be a constraint for CSP plants. It has been estimated that the electricity requirements of the whole of USA, could be generated with CSP plants occupying an area of a hundred square miles. CSP could be combined with conventional devices, such as, steam turbines, and it is possible to scale up CSP plants to several hundred megawatts, using well-established technologies.

Apart from electricity generation, CSP plants can be used to heat/cool buildings, to desalinize water, and to produce fuels like hydrogen. In areas where water is scarce, dry coolers may be used. In some arid countries, cogeneration of heat for desalinization and power may turn out to be an attractive proposition.

The constraint of intermittency of solar energy can be got over either by storing heat and conversion to electricity when solar energy is unavailable, or to have a fossil fuel backup that uses the same steam cycle as the CSP plant (this needs only an additional burner).

4.5.4.2 Description of CSP technology

The solar flux is concentrated in three ways, with different flux concentration ratios: troughs (30–100), towers (500–1000) and dishes (1000–10,000) (Figure 4.5.2).

Troughs are parabolic trough-shaped mirror reflectors. They concentrate sunlight onto receiver tubes, thereby heating a thermal transfer fluid, such as, mineral oils, molten salts and water (direct steam generation). Molten salts are often used for heat storage, but may in future, be replaced by phase-change materials. Integrated Solar

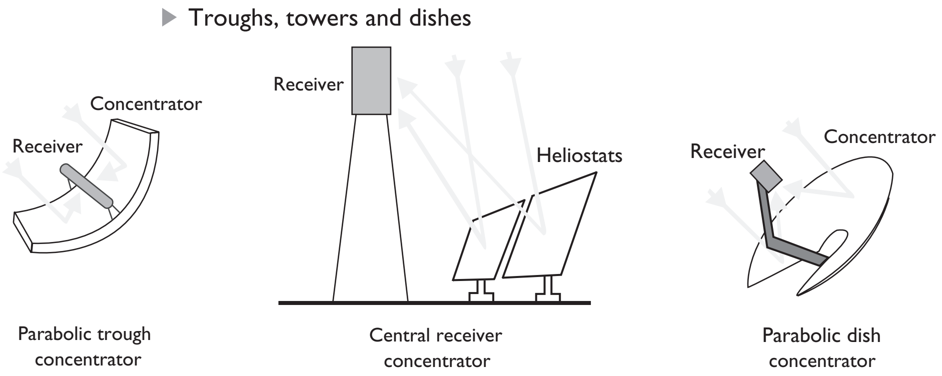

Figure 4.5.2 Troughs, Towers and Dishes.

Source: *Energy Technology Perspectives*, 2008, p.381.

Combined cycle plants use solar heat (350–400°C) and fossil fuels. Trough plants offer a maximum concentration of 200 suns, maximum temperatures of 400°C, solar-to-thermal efficiency of 60% and solar-to-electric efficiency of 12%. In the case of Fresnel collectors, the absorber is fixed in the space above the mirror field. Fresnel collectors are cheaper, but less efficient. Compact Fresnel linear collectors which are more efficient, are being developed. A 354 MW trough plant has been in operation in California. Algeria and Spain are building trough plants.

Towers: Consist of flat, double-axis tracking heliostats. There are several designs, depending upon the heat transfer fluid, which may be molten salts and saturated steam. Italy, Spain, France, Ukraine, Japan and USA have built tower plants of capacity of few tens of MWs. South Africa is developing a large tower project (100 MW in a single tower).

Dishes: Parabolic dish-shaped reflectors concentrate sunlight in two dimensions and run a small Stirling engine (about 10 kW capacity) or turbine at the focal point.

4.5.4.3 Costs

Investments costs for trough plants are in the range of USD 4–9/W, depending upon the local solar conditions and construction costs. Capital costs for 10 MW tower plant are in the range of USD 9/W, but will be cheaper for large plants. Capital costs for dishes are over USD 10/W, but the prices are going down.

Current costs for electricity production are in the range of USD 125–225/MWh, depending on the location of the plant. Both the capital and O&M costs can be brought down, by using large turbines (which allow better conversion rates) and smaller mirror surface.

Increased volume production, plant scale-up and technological advances would bring down costs. If in the next 10–15 years, CSP capacities of 5000 MW are built, the electricity generation costs may come down to USD 43–62/MWh for trough plants, and USD 35–55/MWh for tower plants.

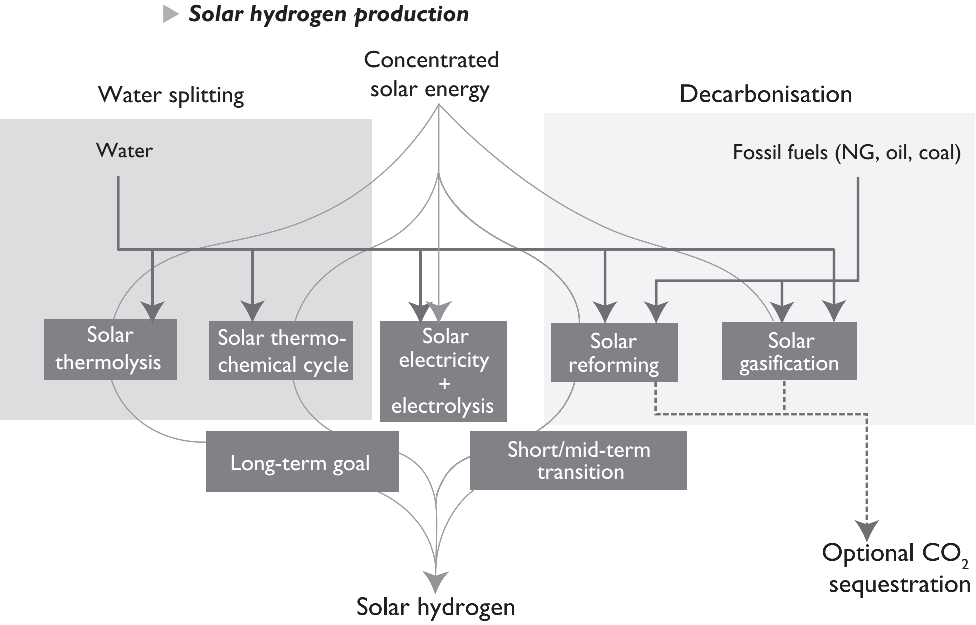

Figure 4.5.3 Solar hydrogen production.

Source: Steinfield, 2005.

4.5.4.4 Projected R&D efforts

R&D in the following areas will improve efficiencies and bring down costs:

i Direct steam generation for trough plants. Fundamental studies on flow patterns and heat transfer in horizontal tubes will help in identifying cheaper substitutes for mineral oil with water, and more efficient ways of using superheated steam.

ii Towers using pressurized air with solar hybrid gas turbine. The gas turbine in the French Pegase project has achieved higher power conversion efficiencies by using high-temperature solar heat, further heated by fossil fuel burning.

iii CSP plants in arid areas are being increasingly used to desalinize brackish water and seawater, while producing power. If the solar plant delivers exhaust steam from the turbine at a temperature of 70°C, the heat can be used for desalination. Thus a 100 MW plant can produce 21,000 m^3 of fresh water per day (DLR, 2007).

iv Solar energy can be used for the production of hydrogen and metals through solar thermolysis. Production of hydrogen from water is an endothermic process. Concentrated solar radiation provides the high-temperature process heat needed for the purpose. Figure 4.5.3 (source: Steinfield, 2005) depicts the various routes for hydrogen production from solar energy. Solar-assisted fossil fuel steam reforming is in the advanced stages of development. CO_2 emissions in the extractive metallurgical industries can be reduced through solar thermal, carbothermal and electrothermal reductions of metal oxides.

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SECTION-V
QUO VADIS?

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PREAMBLE

The global energy security involves two goals for the period, 2005–2050: (i) Energy development has to be managed to facilitate the projected four-fold increase of global GDP during the period, and (ii) 50–80% reduction of global CO_2 emissions by 2050 compared to 2000 levels, in order to restrict the temperature rise to 2°C. This is to be accomplished through greater energy efficiency, greater use of renewable and nuclear power, CO_2 Capture and Storage (CCS) on a massive scale, and development of carbon-free transport. The chapter provides the database which individual countries can make use of to customize their portfolios by choosing the precise mix of CCS, renewables and nuclear technology to decarbonise the power sector, to suit their resource position, and biophysical and socioeconomic environments. Almost any country in the world can make use of one option or another. The International Energy Agency, Paris, came up with fourteen key roadmaps on the supply side and demand side, to achieve a sustainable energy future. A great deal of basic and applied science research is needed to underpin the new technologies. For instance, the safe sequestration of carbon dioxide and radioactive waste requires a good understanding of the complex interactions between the pressurized fluids and porous rock.

CCS (Carbon dioxide Capture and Storage) is the single most important technology for CO_2 savings, accounting for 14% in ACT scenario, and 19% in BLUE scenario. CCS typically consists of three steps: capture, transport, and storage. Capture is the most expensive step; energy-consuming processes are involved and the target of the technology research is being focused on the cost reduction. Post-combustion capture is now the most mature option, although it is expensive and energy-intensive, while pre-combustion capture (IGCC) is estimated to have the lowest overall costs. Risks to human health and safety arise (almost) exclusively from elevated CO_2 concentrations in ambient air, either in confined outdoor environments, in caves, or in buildings. At concentrations above ~2%, CO_2 has a strong effect on respiratory physiology, and at concentrations above 7–10%, it can cause unconsciousness and death.

France which has a population of 63 million, has hardly any resources of fossil fuels. By 1960s, France was producing 40 TWh of hydroelectricity, which was 60% of the electricity production in the country. By 1970s, all the hydroelectric potential was tapped. Nuclear science flourished in France, ever since Bequerel and the Curies discovered the phenomena of radioactivity in early twentieth century. France took a major decision to go in for nuclear power in a big way. In 2006, France which had 59 reactors with a capacity of 63 GWe, produced 429 TWh of electricity, which is 78% of the total electricity production in the country, the highest proportion in the world. Also France produces the cheapest electricity and has the lowest carbon emissions, in Europe. France contributed greatly to the development of nuclear power in the world. It standardized the design of Pressurised Water Reactors (PWR) reactors and also sited 2–6 reactors at one place. Standardization allows also a very efficient return of experience because any lesson learned on one unit can be applied effectively to all its identical twins. Standardization facilitates the training of operation and maintenance teams who can move from one plant to the other without losing their efficiency. France has taken the lead in developing the EPR (European Pressurised Water Reactor), which is safe and economical and produces less waste. The French developed ways of recycling the plutonium extracted from the spent PWR fuel assemblies and mixing it with uranium to fabricate the Mixed Oxide Fuel ("MOX"). In 2000, the French Government has set up AREVA group which operates in every area of the nuclear cycle, ranging from uranium exploration to vitrification and disposal of nuclear wastes.

5.1 GLOBAL ENERGY SECURITY

U. Aswathanarayana
India

5.1.1 Introduction

Global stability and prosperity are critically dependent upon the availability of *secure*, *reliable* and *affordable* energy supplies. Though coal deposits occur in many parts of the world, their use for energy generation has serious environmental and climate change impacts. Oil use is much less polluting, but oil and natural gas resources are concentrated in a small number of countries. For these reasons, reduction in the use of fossil fuels is the key energy policy target of many countries. Besides this, about 69% of all CO_2 emissions are related to energy supply – the greater the CO_2 emissions, the greater the climate change (as manifested by global warming and sea level rise, etc.).

The relationship between emissions and climate change is indicated in Table 5.1.1.

Restricting the temperature rise to 2°C would involve the 50–80% reduction of global CO_2 emissions by 2050 compared to 2000 levels. It is generally believed that temperature rise greater than 2°C may set in motion climate changes which may prove irreversible. Stern (2007) has marshaled cogent arguments to show that the benefits of limiting the temperature rise to 2°C would outweigh the costs of doing so, though there is difference of opinion in regard to the assumptions that underlie the relative calculations.

5.1.2 Demographic assumptions

The world population which is 6.5 billion now, is expected to go up to 9.2 billion by 2050. China is the most populous country in the world, followed by India. They will continue to be the most populous countries in 2050 too. India is expected to overtake China in population by 2030 (Table 5.1.2, source: United Nations, 2007).

Table 5.1.1 Carbon dioxide emissions and climate change.

Temperature increase (°C)	*All GHG's (ppm CO_2 eq.)*	*CO_2 (in ppm)*	*CO_2 emissions (2050) (% of 2000 emissions)*
2.0–2.4	445–490	350–400	–85 to –50
2.4–2.8	490–535	400–440	–60 to –30
2.8–3.2	535–590	440–485	–30 to +5
3.2–4.0	590–710	485–570	+10 to +60

Source: IPCC, 2007.

Table 5.1.2 Population projections (in millions), 2005–2050.

Country	*2005*	*2015*	*2030*	*2050*
China	1,315,844	1,388,600	1,438,394	1,408,846
India	1,103,371	1,302,535	1,489,653	1,658,270
World	**6,464,750**	**7,295,135**	**8,246,665**	**9,191,287**

Source: United Nations, 2007.

Today half of the world's population lives in urban areas. The percentage of urban dwellers is projected to increase to 60% by 2030, and to 70% by 2050. The urban population in the Developing countries is expected to increase as follows during 2000–2030:

	2000 (in millions)	*2030 (in millions)*
Asia	1360	2640
Africa	294	742
Latin America & the Caribbean	394	609

As a consequence of these shifts, the developing countries will have 80% of the world's urban population by 2030.

The global median age today is 28 years. The proportion of population of 60 years and over in age, is expected to rise from 11% in 2007 to 22% in 2050. This will have important consequences for energy consumption, as the lifestyles of the older people are different from those of the younger people.

5.1.3 Macroeconomic assumptions

The GDP Index (with base100 for 2005) for the period, 2005–2050 (in terms of Purchasing Power Parity) of selected economies in the world, are given in Table 5.1.3.

An analysis of the above data leads to the following conclusions about GDP growth. During the period, 2005–2050, the global GDP is expected to grow four-fold (to USD

Table 5.1.3 GDP Index changes.

	2015	*2030*	*2050*
OECD	131	174	230
North America	133	184	257
United States	133	164	248
Europe	130	170	195
European Union	128	168	193
Pacific	127	161	221
Japan	120	146	189
Transition economies	166	254	407
Russia	159	240	469
Developing countries	192	366	728
Developing Asia	208	421	854
China	226	463	977
India	215	501	1015
Middle East	169	279	495
Africa	162	276	560
Latin America	151	228	396
Brazil	146	221	385
World	**157**	**256**	**428**

Source: *Energy Technology Perspectives*, 2008, p. 571.

227 trillion per year). The economies of European countries and Japan are expected to double, while that of North America will grow by two and half times. The main growth will be in developing countries. The GDP of China and India will grow tenfold. By 2050, the Chinese GDP will be 70% higher than that of USA, and the Indian GDP will be comparable to OECD Europe.

That during the period, 2005–2050, there will be sharp changes in the contribution of the various regions to the global GDP, is evident from Table 5.1.4.

5.1.4 Per capita GDP, energy use and carbon dioxide emissions

The increase in per capita GDP is generally linked to greater energy use, which entails higher carbon dioxide emissions. However, the example of a number of countries, such as, France, Germany, Japan, Norway and Sweden, shows that it is indeed possible to maintain a high standard of living (as manifested by high GDP) while using comparatively less energy and emitting less carbon dioxide, through the diversification of the energy mix (Table 5.1.5). For instance, nuclear power accounts for about

Table 5.1.4 World GDP by region in 2005 and 2050 (based on Purchasing Power Parity).

Area	*2005 (in%)*	*2050 (in%)*
OECD North America	27	16
OECD Europe	25	12
OECD Pacific	11	6
China	10	23
India	4	10
Other Asia	7	15
Former Soviet Union (FSU)	4	5
Middle East	2	2
Latin America	6	6
Africa	4	5

Source: *Energy Technology Perspectives*, 2008, p. 570.

Table 5.1.5 Per capita GDP, energy use and CO_2 emissions.

Country	*Per capita GDP (x $2000/capita)*	*Per capita energy usage (GJ/capita)*	*Per capita CO_2 emissions (t CO_2/capita)*
India	0.54	22	1.02
China	1.3	52	3.65
France	22.8	186	6.22
Germany	23.7	177	10.29
Canada	24.6	354	17.24
Sweden	29.3	252	5.8
United States	36.4	332	19.73
Japan	38.6	176	9.52
Norway	39.3	253	7.91

Source: International Energy Agency, *"Key World Energy Statistics"*, 2006.

80% of electricity in France. Also, France has lowest electricity costs, and lowest per capita carbon emissions in Europe.

5.1.5 ACT and Blue scenarios

It is generally accepted that in order to face the emerging challenges, the global energy economy needs to be transformed profoundly in the coming decades in terms of ways by which energy is supplied and used. This is to be accomplished through greater energy efficiency, greater use of renewable and nuclear power, CO_2 Capture and Storage (CCS) on a massive scale, and development of carbon-free transport. Among these, improvement in energy efficiency is the least expensive and most effective pathway.

The International Energy Agency (2008) came up with two scenarios:

1. ACT scenarios which makes use of technologies that already exist or likely to be available soon, to bring the CO_2 emissions back to current levels by 2050. Emissions need to peak between 2020 and 2030, costing USD 50 per tonne of CO_2 saved when fully commercialized. IEA estimates that to realize the ACT scenario, an additional investment of USD 17 trillion will be needed between now and 2050. This works out to USD 400 billion per year, which is roughly equivalent of GDP of The Netherlands.
2. BLUE scenarios, whereby emissions must be reduced by 50–85% of the current levels by 2050, in order for the global warming to be confined to the IPCC-recommended figure of 2°C–2.4°C. This is more expensive than ACT scenarios as it involves the deployment of technologies which are yet to be developed. Additional investment needed to realize the blue scenario is estimated by IEA to be USD 45 trillion between now and 2050. This works out to USD 1.1 trillion per year from now to 2050. This is roughly equivalent of GDP of Italy.

The additional investments needed under ACT and BLUE scenarios appear staggering, but it should be emphasized that these are not net costs. The technology investments in energy efficiency, in many renewables and in nuclear power, have the effect of drastically reducing the fuel requirements. "In both ACT and Blue scenarios, the estimated total undiscounted fuel cost savings for coal, oil and natural gas over the period to 2050, are greater than the additional investment required" (*Energy Technology Perspectives,* 2008, p. 40). For ACT scenario, fuel savings exceed additional investments at the discount rate of 3%. The discount rate has, however, to be 10% to fulfill this condition in the case of BLUE scenarios. Thus, the additional investments are cost effective, particularly so in the case of the energy efficiency.

5.1.6 Decarbonising the different sectors

5.1.6.1 Decarbonisation of the power sector

The power sector can be decarbonised in a number ways. Countries, such as, China and India, which are heavily dependent on coal for power production, could still use coal so long as CCS (Carbon dioxide Capture and Storage) is built into coal-fired power plants. CCS is the single most important technology for CO_2 savings, accounting for 14% in ACT scenario, and 19% in BLUE scenario. By 2050, renewables (wind, PV, CSP and biomass) would account for 46% of the power in the BLUE scenario, leading to 21% of the CO_2 savings. Generating nuclear power at the rate of 32 GW/yr between now and 2050 would lead to 6% savings in CO_2.

Total additional investment in the power sector amounts to USD 0.7 trillion in the ACT Scenario and USD 3.6 trillion in the BLUE scenario. BLUE scenario is more expensive not only because the new technologies that are proposed to be used are more expensive, but also because coal-fired stations not suitable for CCS, will need to be closed before the end of their technical life.

Table 5.1.6 gives the annual rates at which new power generation capacity needs to be added under ACT and BLUE scenarios.

Thus, individual countries can make use of the above information to customize their portfolios by choosing the precise mix of CCS, renewables and nuclear technology to decarbonise the power sector, to suit their resource position, and biophysical and socioeconomic environments. Almost any country in the world can make use of one option or another. Some countries, such as, China, India, and USA, are in a position to make use of all the options. Countries like Japan may go in for nuclear energy, hydropower and geothermal power. Those Sub-Saharan countries which have no coal, oil or hydropower, may go in for Solar PV and CSP.

5.1.6.2 Decarbonisation of the transport sector

ACT scenario involves the use of low carbon footprint biofuels in trucks, shipping and air transport, improvements in the efficiency of conventional vehicles, curbing the use of

Table 5.1.6 Annual rates of increase in power generation under different scenarios.

Type of power generation	*ACT scenario*	*BLUE scenario*
Coal-fired with CCS	30 CCS coal-fired plants (500 MW, each) per annum	35 CCS coal-fired plants (500 MW, each) per annum
Gas-fired with CCS	1 CCS gas-fired plant (500 MW, each) per annum	20 CCS gas-fired plants (500 MW, each) per annum
Nuclear	24 nuclear power plants (1000 MW, each) per annum	24 nuclear power plants (1000 MW, each) per annum
Hydro	1/5 of Canada's hydropower capacity* per annum	1/5 of Canada's hydropower capacity* per annum
Biomass plants	30 biomass plants (50 MW, each), per annum	100 biomass plants (50 MW, each), per annum
Wind-onshore	2900 wind turbines (4 MW, each) per annum	14000 wind turbines (4 MW, each) per annum
Wind-offshore	775 wind turbines (4 MW, each) per annum	3750 wind turbines (4 MW, each) per annum
Geothermal	50 Geothermal units (100 MW, each) per annum	130 Geothermal units (100 MW, each) per annum
Solar PV	115 million m^3 solar panels, per annum	215 million m^3 solar panels, per annum
Solar CSP	45 CSP plants (250 MW, each) per annum	80 CSP plants (250 MW, each) per annum

* Canada is the world's largest hydropower producer (~71 GW of installed capacity; 355.4 TWh in 2006).

Source: *Energy Technology Perspectives*, 2008, p. 42.

larger and heavier vehicles, and massive improvements in public transportation in order to reduce the use of a large number of private vehicles. Additional investments needed are USD17 trillion. BLUE scenario envisages the use of new kinds of vehicles, which use non-hydrocarbon materials, such as electric batteries and hydrogen fuel cells. BLUE scenario needs to have about a billion electric and fuel cell vehicles on the roads by 2050. These vehicles are costlier than the presently used vehicles by about USD 6500.

Additional investment needs in the transport sector under the BLUE scenario are USD 33 billion.

5.1.6.3 Decarbonisation of the industry sector

Manufacturing industry accounts for about one-third of global energy use and CO_2 emissions. Iron and steel and cement industries, and chemical and petrochemical industries are the principal emitters of CO_2. Heavy industries which are energy-intensive have been traditionally careful in energy use, to keep down costs. Efficiency gains are still possible in less energy-intensive industries through the use of more efficient motor drive systems, and combining heat and power. In the ACT scenario, energy-related CO_2 emissions are projected to be 63% higher in 2050 than in 2005. In the BLUE scenario, CO_2 emissions will be 22% lower than now, because of the widespread application of CCS. There will be a saving of about 10 Gt of CO_2 per year. The upgrading of the industrial plant in the steel, cement and pulp sectors, and extensive deployment of CCS, under the BLUE scenario involves additional investment of USD 2.5 trillion.

5.1.6.4 Decarbonisation of the buildings and appliances sector

Under the ACT scenario, decarbonisation measures include the design of building-shell measures, heat pumps, solar heating, use of high-efficiency appliances and lighting, shifting to renewable, low-carbon electricity, etc. These need additional investment of USD 2.6 trillion. The BLUE scenario involves the use of yet to be developed and expensive technologies, and hence need investment of USD 7.4 trillion in residential and service sectors.

5.1.7 Energy efficiency trends

Energy efficiency has been improving at the rate of 1% in the OECD countries. This is not adequate. ACT scenario envisages global energy efficiency increase at the rate of 1.4%, while it would be 1.7% under the BLUE scenario. Though the difference between the two scenarios in only 0.3%, it manifests itself in the form of additional energy savings of 1544 Mtoe in 2050. Incidentally, this figure is about one-fifth of the total final energy use now. Both Developing and Industrialised countries stand to benefit a great deal through improvements in energy efficiency.

5.1.8 Research & Development, demonstration and deployment

BLUE scenarios involve the development of new technologies, and refinement and cost reduction of the existing technologies. Many OECD countries spend less than 0.03%

of GDP on R&D Japan is an exception in that it spends 0.08% of GDP. Private sector R&D effort is much larger than that of the public sector. Enormous R&D effort is needed to promote "further advances and low-cost solutions in respect of critical technologies, such as solar PV, advanced coal plant, advanced biofuels, CCS, electric batteries, fuel cells and hydrogen production" (*Energy Technology Perspectives*, 2008, p. 44). Government support is needed for full-scale demonstration of coal plants with CCS. To underpin the technology effort, basic sciences, such as, geology, physics, chemistry, biochemistry, nanotechnology, applied mathematics, etc. need to be developed. For instance, the safe sequestration of carbon dioxide and radioactive waste, requires a good understanding of the complex interactions between the pressurised fluids and porous rock (DePaolo and Orr, 2008). Most new technologies are costlier than the existing ones. Reduction in costs and adapting the products to the markets are only possible through technology learning and deployment in the market place. Second generation solar and biofuels have the greatest potential in this regard. The deployment of new technologies between now and 2050 would need an additional investment of USD 2.8 trillion under the ACT scenario, and USD 7 trillion under BLUE scenario.

Carefully designed regulations and standards for buildings, appliances and vehicles have the potential to lead to low-energy and zero-energy buildings, and four-fold reduction in the CO_2 intensity of vehicles. Under the ACT scenario, incentive mechanisms should be such that when fully commercialized, they have a marginal cost of USD 50 per tonne of CO_2 saved. In the case of BLUE scenario, the corresponding figure could be USD 200.

While there is general agreement in respect of the need to address climate change, specific projects undertaken for the purpose may face public opposition. Neither ACT nor BLUE roadmaps are possible without public support. A number of international networks, such as, EU Energy Technology programmes, Asia Pacific Partnerships, Carbon Sequestration Leadership Forum, Biofuels Partnership, International Partnership for a Hydrogen Economy, Generation IV International Forum and the Global Nuclear Energy Partnership, etc. have been actively working to find solutions to the global energy problems.

5.1.9 Key roadmaps for sustainable energy future

The international Energy Agency, Paris, came up with the following key roadmaps to achieve a sustainable energy future (*Energy Technology Perspectives*, 2008, p. 46).

Supply side	*Demand side*
• CCS fossil-fuel generation	• Energy efficiency in buildings and appliances
• Nuclear power plants	• Heat pumps
• Onshore and offshore wind	• Solar space and water heating
• Biomass integrated-gasification combined-cycle and co-combustion	• Energy efficiency in transport
• Photovoltaic systems	• Electric and plug-in vehicles
• Concentrating solar power	• H_2 fuel cell vehicles
• Coal: integrated-gasification combined cycle	• CCS in industry, H_2 and fuel transformation
• Coal: Ultra-supercritical	• Industrial motor systems
• Second-generation biofuels	

5.2 CARBON DIOXIDE CAPTURE AND STORAGE

Takashi Ohsumi
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5.2.1 Overview

It has been well recognized that the global warming concerns could be a limiting factor for human kind to use the fossil fuel. In 1973, the Club of Rome commissioned the book "Limits to Growth", where the author Dennis Meadows warned that the world would run short of resources within a century, putting the planet at risk of expanding hunger as well as economic and social disaster. In response to this warning, Marchetti (1977) discussed the fossil-fuel era with and without carbon dioxide storage as such depicted in Figure 5.2.1. His proposal was the ocean injection of carbon dioxide captured in the process of fossil fuel energy use.

This chapter describes the technology of carbon dioxide capture and storage (CCS), an emerging energy technology for tackling the global warming problems.

5.2.2 Economics and technological status of carbon dioxide capture and storage

Carbon dioxide capture and storage (CCS) typically consists of three steps: capture, transport, and storage. Capture is the most expensive step; energy-consuming

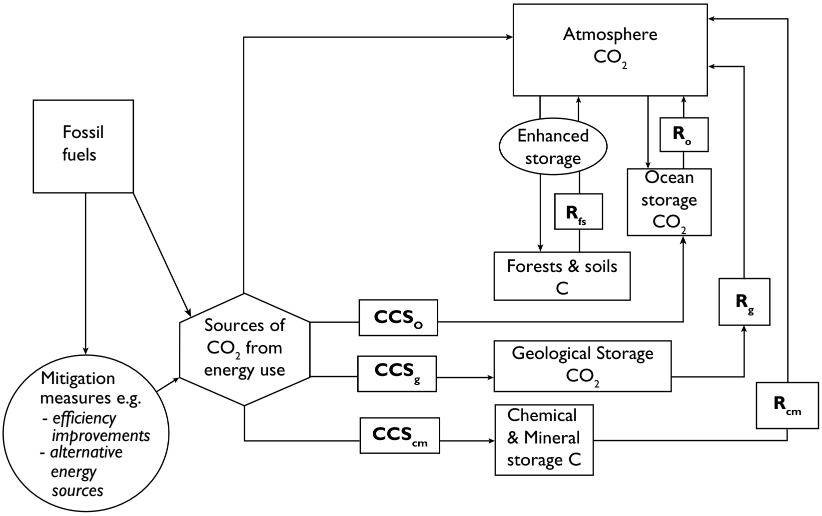

Figure 5.2.1 Schematic diagram of stocks and flows of CO_2 with net flows of captured CO_2 to each reservoirs. The labels R indicate the release flows of CO_2 once stored in Ocean (CCS_o), in Geosphere (CCS_g), or as in the form of Chemical and Mineral storage (CCS_{cm}). Note that the longer-term carbon cycle involves the ocean and weathering processes as described by Ohsumi (1995). [cited from IPCC Special Report on Carbon Dioxide Capture and Storage, 2005]

processes are involved and the target of the technology research is being focused on the cost reduction. Transporting CO_2 by pipeline, truck, or ship is a well-understood and established practice. For these 30 years or more, in North America, millions of tons of CO_2, mostly from naturally occurring formations, are moved each year by the oil and gas industry for enhanced oil recovery (EOR).

Storage resembles EOR in practice of injecting CO_2 through wells into deep underground formations. Additional scientific understanding and practical experience is needed to define best practices and standards for the large-scale storage. CO_2 is also stored in the ocean and even on land as described later, although these options are not well evaluated for the associated risks and merits.

5.2.2.1 Capture

Carbon dioxide capture requires separating from industrial and energy-related process emissions into relatively pure streams and pressurizing it for transport and storage. Only large point sources of CO_2 emissions such as power plants, steel mills, cement plants, refineries, ammonia and fertilizer plants are currently targeted as candidates for CCS. These sources account for nearly half of global CO_2 emissions. In the case that electrical vehicles are widely introduced in the future, the contribution of CCS to the CO_2 emission reduction would be much significant. Moreover, if CCS technology is employed to the power plants using biomass fuels, this means negative CO_2 emission to the atmosphere. Note that in a long run, if the transport and storage are developed as an essential infrastructure in the society, capture processes could be applied instantaneously to even fossil fuel-based distributed powers, because the small-scale capture from flue gases is an established technology at the present.

There are currently four approaches for capturing CO_2. Post-combustion capture involves separation of the CO_2 from the flue gas, and is currently the technology of choice for most small-scale, commercial carbon capture applications. CO_2 can also be separated and captured from fuel before burning in pre-combustion decarbonization. Integrated gasification combined-cycle (IGCC) power plants use this approach. Oxy-fuel combustion is the third, emerging option to achieve a relatively pure stream of pressurized CO_2. This process uses oxygen instead of air for combustion, and produces a concentrated CO_2 exhaust stream. Lastly, CO_2 can be captured in limited quantities from industrial practices that do not involve fuel combustion, such as natural gas purification as in the case of Sleipner gas field (Korbol and Kaddour, 1994).

Post-combustion capture is now the most mature option, although it is expensive and energy-intensive, while pre-combustion capture (IGCC) is estimated to have the lowest overall costs. Oxyfuel combustion is still in the demonstration phase, and more testing, particularly at larger scales, is needed.

Reducing costs will be the most important objective in the near-term, but other uncertainties must also be resolved. Viable capture technologies will almost certainly be needed for both new plants and for retrofit of existing plants. Requirements that new plants be "capture ready" – designed with additional room to install capture technology at a later date – may guide utility investment decisions with greater certainty.

5.2.2.2 *Transport*

After capture, CO_2 is delivered from the point source to the storage site. Dedicated CO_2 pipelines are the most efficient transport mode for shipment, but tanker lorries and ships can also used, permitting flexibility of the logistics. There are over 5,800 km of pipelines dedicated to CO_2 transport in the U.S.A., mainly for use in enhanced oil recovery (EOR) projects. Transport technology and regulations are considered relatively mature, at least relative to capture and underground storage; economies of scale and creation of a centralized pipeline network could lower costs marginally, but major cost reductions are unlikely.

5.2.2.3 *Storage*

Originally, when it was proposed by Marchetti (1977), the CCS scheme assumed that the storage sites be in the ocean. The concept of CO_2 underground geological storage in the context of the global warming concerns was propounded by Steinberg (1984). Steinberg compared the cost of storage, that is injection into a well or deposition onto the ocean floor through a pipe, and concluded that the costs are comparable for both methods (ocean and underground). However, as a scientist in North America, he knows well that the CO_2-EOR is almost matured technology and he might think that after Lake Nyos disaster (Kusakabe et al., 1989) that occurred in 1986, the underground storage is more feasible from viewpoint of risk perception of the public.

In terms of storage cost, the solid-CO_2 storage concept proposed by Seifritz (1992) gives us the upper limit cost we can pay: the storage cost should not exceed the liquefaction cost. It is because you can make one kilogram of solid-CO_2 from two kilograms of liquid CO_2, whereas the remaining one-kilogram of the CO_2 transforms into CO_2 gas phase at normal pressure and temperature. This concept typically shown as in Figure 5.2.2, solid-CO_2 pile could be a reference case for the CCS storage schemes in terms of risk perception and also of cost assessment.

5.2.2.4 *Cost of carbon dioxide capture and storage*

For fossil-fuel power stations, many studies were carried out on the additional cost estimate in various conditions. IPCC (2007) showed that the cost for every tonne of CO_2 avoided and discussed on the potentials in terms of Wh/yr for the costs lower than 20US$/t CO_2-eq avoided and those lower than 50US$/t CO_2-eq avoided. The potentials and cost estimates are for the world opportunities by 2030.

5.2.3 Underground geological storage

5.2.3.1 *Capacity of the storage*

The effectiveness of geological storage depends on a combination of physical and geochemical trapping mechanisms. The most effective storage sites are those where CO_2 is immobile because it is trapped permanently under a thick, low-permeability seal, or is converted to solid minerals, or is adsorbed on the surfaces

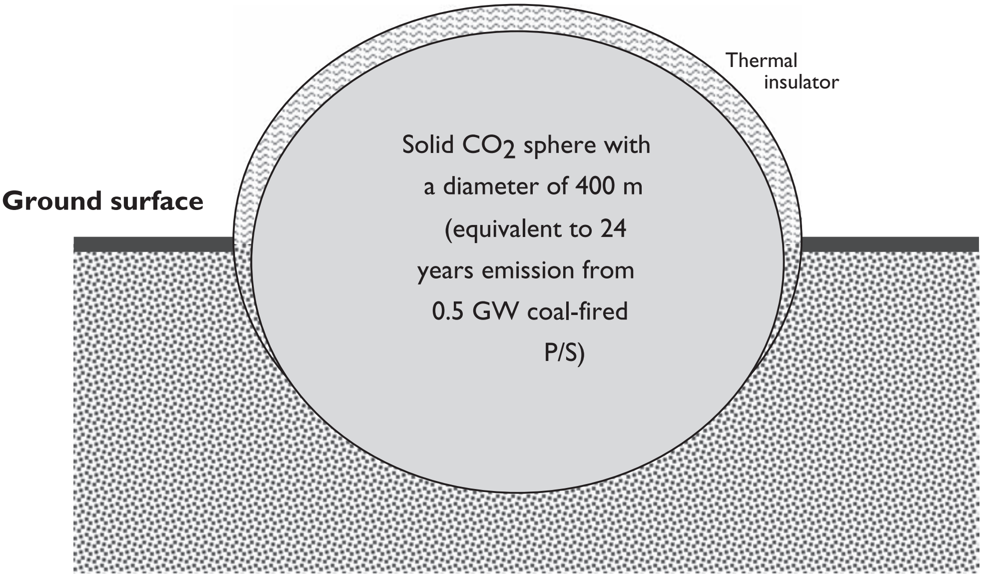

Figure 5.2.2 Conceptual settings of land surface sequestration of CO_2 in the form of solid.

of coal micropores, or through a combination of physical and chemical trapping mechanisms.

Geological storage of CO_2 can be undertaken in a variety of geological settings in sedimentary basins. Within these basins, oil fields, depleted gas fields, deep coal seams, and saline formations are all possible storage formations. Subsurface geological storage is possible both onshore and offshore, with offshore sites accessed through pipelines from the shore or from offshore platforms. The continental shelf and some adjacent deep-marine sedimentary basins are potential offshore storage site. In addition to storage in sedimentary formations, some consideration has been given to storage in basalt, and organic-rich shale etc. In Japan, geothermal reservoirs are also regarded as possible candidates (Ito et al., 2005) where injected CO_2 may react with surrounding minerals, e.g., Ca feldspar and anhydrite, and may precipitate $CaCO_3$ at locations that are remote from the injection point, forming cap rocks (see Figure 5.2.3).

In general, geological storage sites should have (1) adequate capacity and injectivity, (2) a satisfactory sealing caprock, or confining unit. Identifying potential sites for CO_2 geological storage and estimating their capacity on a regional or local scale should conceptually be a simple task. The differences between the various mechanisms and means of trapping suggest in principle the following methods:

1. For volumetric trapping, capacity is the product of available volume (pore space) and CO_2 density at in situ pressure and temperature.
2. For solubility trapping, capacity is the amount of CO_2 that can be dissolved in the formation fluid (oil in oil reservoirs, brackish water or brine in saline formations).

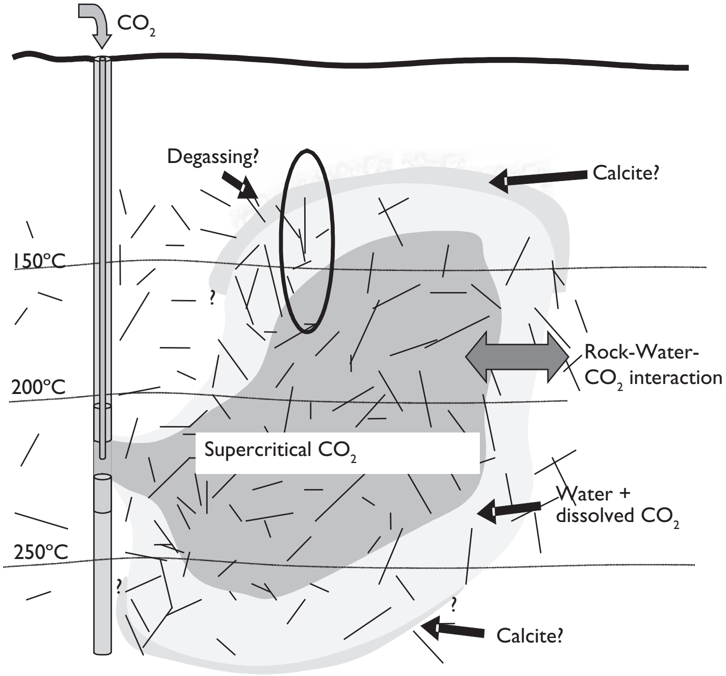

Figure 5.2.3 Concept of CO_2 sequestration in geothermal fields (See colour plate 15).

3 For adsorption trapping, capacity is the product of coal volume and its capacity for adsorbing CO_2.
4 For mineral trapping, capacity is calculated on the basis of available minerals for carbonate precipitation and the amount of CO_2 that will be used in these reactions.

For example, an early estimate of aquifer storage potential in the world (Koide et al., 1992) adopted the method 2 listed above.

The major impediments in applying these simple methods for estimating the capacity for CO_2 storage in geological media are the lack of data, their uncertainty, the resources needed to process data when available, and the fact that frequently more than one trapping mechanism is active. This leads to two situations:

1 Global capacity estimates have been calculated using simplifying assumptions and very simplistic methods, and hence are not reliable.
2 Country- and region/basin-specific estimates are more detailed and precise, but still affected by the limitations imposed by availability of data and the methodology used. Country/basin specific capacity estimates are only available for North America, Western Europe, Australia, and Japan.

The capacity estimates are summarized in Table 5.2.1.

Table 5.2.1 Storage capacity for several geological storage options. The storage capacity includes storage options that are not economical.

Reservoir type	*Lower estimate of storage capacity (GtCO$_2$)*	*Upper estimate of storage capacity (GtCO$_2$)*
Oil and gas fields	675	900
Unminable coal seams (ECBM)	3–15	200
Deep saline formations	1000	Uncertain, but possibly 10000

5.2.3.2 Technical background

Injection well technologies

Many of the technologies required for large-scale geological storage of CO$_2$ already exist. Drilling and completion technology for injection wells in the oil and gas industry has evolved to a highly sophisticated state, such that it is now possible to drill and complete vertical and extended reach wells (including horizontal wells) in deep formations, wells with multiple completions, and wells able to handle corrosive fluids. Based on extensive oil industry experience, the technologies for drilling, injection, stimulations, and completions for CO$_2$ injection wells exist and are being practiced with some adaptations in current CO$_2$ storage projects. In a CO$_2$ injection well, the principal well design considerations include pressure, corrosion-resistant materials, and production and injection rates.

The design of a CO$_2$ injection well is very similar to that of a gas injection well in an oil field or natural gas storage project. The technology for handling CO$_2$ has already been developed for EOR operations and for the disposal of acid gas. Horizontal and extended reach wells can be good options for improving the rate of CO$_2$ injection from individual wells.

Monitoring and verification technology

Monitoring is needed for a wide variety of purposes. Specifically, monitoring can be used to:

- Ensure and document effective injection well controls, specifically for monitoring the condition of the injection well and measuring injection rates, wellhead, and formation pressures. Petroleum industry experience suggests that leakage from the injection well itself, resulting from improper completion or deterioration of the casing, packers, or cement, is one of the most significant potential failure modes for injection projects (Perry, 2005; Apps, 2005).
- Verify the quantity of injected CO$_2$ that has been stored by various mechanisms, such as depicted in Figure 5.2.4.
- Optimize the efficiency of the storage project, including utilization of the storage volume, injection pressures and drilling of new injection wells.
- Demonstrate with appropriate monitoring techniques that CO$_2$ remains contained in the intended storage formation(s). This is currently the principal method for assuring that the CO$_2$ remains stored and that performance predictions can be verified.

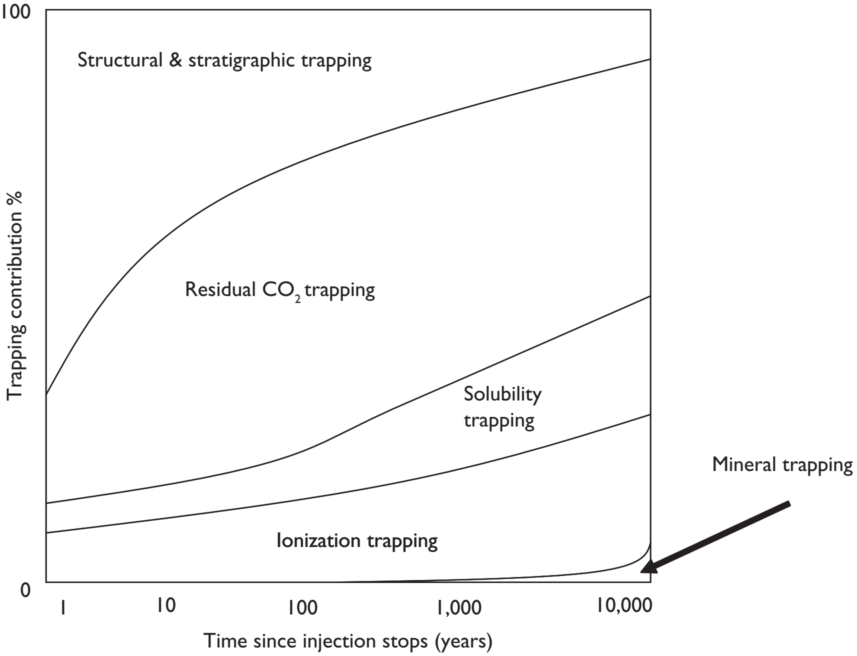

Figure 5.2.4 Trapping mechanisms typically in "aquifer storage" concept in relation to time lapse. Modified from IPCC (2005). Note that various trapping mechanisms will operate in time courses.

- Detect leakage and provide an early warning of any seepage or leakage that might require mitigating action.

5.2.3.3 Environmental impacts, risks, and risk management

The environmental impacts arising from geological storage fall into two broad categories: local environmental effects and global effects arising from the release of stored CO_2 to the atmosphere. Global effects may alternatively be viewed as uncertainty in the effectiveness of CO_2 storage. Local health, safety, and environmental hazards arise from three distinct causes:

- The direct effects of elevated gas-phase CO_2 concentrations in the shallow subsurface and near-surface environment
- The effects of dissolved CO_2 on groundwater chemistry
- The effects that arise from the displacement of fluids by the injected CO_2

Risks are proportional to the magnitude of the potential hazards and the probability that these hazards will occur. For hazards that arise from locally elevated CO_2 concentrations – in the near-surface atmosphere, soil-gas, or in aqueous solution – the risks depend on the probability of leakage from the deep storage site to the surface. Thus, most of the hazards should be weighted by the probability of release. Regarding those risks associated with routine operation of the facility and well maintenance, such risks are expected to be comparable to CO_2-EOR operations.

Although we have limited experience with injection of CO_2 for the explicit purpose of avoiding atmospheric emissions, a wealth of closely related industrial experience and scientific knowledge exists that can serve as a basis for appropriate risk management.

5.2.4 Processes and pathways for release of CO_2 from geological storage sites

Carbon dioxide that exists as a separate phase (supercritical, liquid, or gas) may escape from formations used for geological storage through the following pathways:

1 Through the pore system in low-permeability caprocks such as mudstones, if the capillary entry pressure at which CO_2 may enter the caprock is exceeded
2 Through openings in the caprock or fractures and faults
3 Through man-made pathways, such as poorly completed and/or abandoned pre-existing wells.

For onshore storage sites, CO_2 that has leaked may reach the water table and migrate into the overlying vadose zone. This occurrence would likely include CO_2 contact with drinking-water aquifers. Depending on the mineral composition of the rock matrix within the groundwater aquifer or vadose zone, the reaction of CO_2 with the rock matrix could release contaminants. The U.S. Environmental Protection Agency (USEPA) has witnessed problems with projects designed to replenish groundwater with rainfall wherein mineralized (fixed) contaminants were inadvertently mobilized in concentrations so as to cause undesirable contamination.

Injection wells and abandoned wells have been identified as one of the most probable leakage pathways for CO_2 storage projects (Gasda et al., 2004; Benson, 2005). When a well is drilled, a continuous, open conduit is created between the land surface and the deep subsurface. If, at the time of drilling, the operator decides that the target formation does not look sufficiently productive, then the well is abandoned as a "dry hole," in accordance with proper regulatory guidelines. Current guidelines typically require filling sections of the hole with cement.

Drilling and completion of a well involve not only creation of a hole in the earth, but also the introduction of engineered materials into the subsurface, such as well cements and well casing. The overall effect of well drilling is replacement of small but potentially significant cylindrical volumes of rock, including low-permeability caprock, with man-made materials that have properties different from those of the original materials. A number of possible leakage pathways can occur along abandoned wells.

5.2.5 Potential hazards to human health and safety

Risks to human health and safety arise (almost) exclusively from elevated CO_2 concentrations in ambient air, either in confined outdoor environments, in caves, or in buildings. Physiological and toxicological responses to elevated CO_2 concentrations are relatively well understood. At concentrations above ~2%, CO_2 has a strong effect on respiratory physiology, and at concentrations above 7–10%, it can cause unconsciousness and death. Exposure studies have not revealed any adverse health effect of chronic exposure to concentrations below 1%. The principal challenge in estimating the risks posed by CO_2 that might seep from storage sites lies in estimating the spatial and temporal distribution of CO_2 fluxes reaching the shallow subsurface, and in predicting ambient CO_2 concentration resulting from a given CO_2 flux. Concentrations in surface air will be strongly influenced by surface topography and atmospheric conditions. Because CO_2 is 50% denser than air, it tends to migrate downwards, flowing along the ground and collecting in shallow depressions, potentially creating much higher concentrations in confined spaces than in open terrain.

5.2.6 Risk management

Risk management entails the application of a structured process to identify and quantify the risks associated with a given process, to evaluate these, taking into account stakeholder input and context, to modify the process to remove excess risks, and to identify and implement appropriate monitoring and intervention strategies to manage the remaining risks.

For geological storage, effective risk mitigation consists of four interrelated activities:

- Careful site selection, including performance and risk assessment, and socio-economic and environmental factors
- Monitoring to provide assurance that the storage project is performing as expected and to provide early warning in the event that it begins to leak
- Effective regulatory oversight
- Implementation of remediation measures to eliminate or limit the causes and impacts of leakage.

Enable quantitative estimates of the degree of risk mitigation that can be achieved by various measures and to establish an appropriate level of monitoring, with intervention options available if necessary. Experience from natural gas storage projects and disposal of liquid wastes has demonstrated the effectiveness of this approach to risk mitigation (Perry, 2005; Wilson et al., 2003; Apps, 2005).

5.2.7 Legal issues

States can regulate subsurface injection and storage of CO_2 within their jurisdiction in accordance with their national rules and regulations. Such rules and regulations could be provided by the mining laws, resource conservation laws, laws on drinking water, waste disposal, oil and gas production, treatment of high-pressurized gases, and others. An analysis of existing regulations in North America, Europe, Japan, and Australia highlights the lack of regulations that are specifically relevant for CO_2 storage and the lack of clarity relating to post-injection responsibilities (IEA Greenhouse Gas R&D Programme, 2003; IOGCC, 2005).

In the U.S.A., the Safe Drinking Water Act regulates most underground injection activities. The U.S. Environmental Protection Agency (USEPA) Underground Injection and Control (UIC) program, created in 1980 to provide minimum standards, helps harmonize regulatory requirements for underground injection activities. The explicit goal of the UIC program is to protect current and potential sources of public drinking water. The Safe Drinking Water Act expressly prohibits underground injection that "endangers" an underground source of drinking water. Endangerment is defined with reference to national primary drinking water regulations and adverse human health effects. For certain types or "classes" of wells, regulations by the USEPA prohibit injection that causes the movement of any contaminant into an underground source of drinking water.

5.3 NUCLEAR POWER IN FRANCE: A SUCCESS STORY

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5.3.1 Introduction

France is a medium size country of 63 million inhabitants, blessed with a mild climate favourable to agriculture, various beautiful landscapes and a long cultural and architectural inheritance – not to mention its well-established tradition of gastronomy – which make it the number one tourist destination. However, in terms of fossil energy resources, France is poor: very little oil and almost no coal and gas left.

It is the main reason why France has been, for now nearly 40 years, developing an intensive electro nuclear program. This program covers the entire industrial cycle (nuclear plants but also all the various stages of nuclear fuel cycle). This program was engaged and continuously carried on within a great consensus among public authorities. So, if France has been always, indeed, visited for the Eiffel Tower, Versailles Palace, the Loire valley castles, gothic cathedrals, the French Riviera and expensive three stars restaurants, it is now also known worldwide for its nuclear power achievements. France is number two in the world, after the USA and before Japan, for the total amount of electricity generated from its 59 nuclear reactors, and number one in terms of percentage of nuclear generation (Table 5.3.1). How and why is it so?

5.3.2 French scientific tradition regarding nuclear science

By the turn of the XIXth century, radioactivity was discovered by Henri Becquerel, Pierre and Marie Curie, who were awarded the Nobel Prize in physics for this discovery. Then in 1934, Frédéric Joliot-Curie and his wife Irène, Marie Curie's daughter, were awarded the Nobel Prize for the discovery of artificial radioactivity. In 1939, a few months after the discovery of nuclear fission by a German team led by Otto Hahn, the French team led by Frédéric Joliot-Curie demonstrated that new neutrons were emitted during a fission, making it possible to establish and sustain

Table 5.3.1 World Nuclear Electricity Generation (2006).

Country	*Production TWh*	*Installed nuclear capacity (GWe)*	*Number of operating reactors*	*% nuclear in electricity production*
United States of America	787	98	103	19
France	429	63	59	78
Japan	292	48	55	30
Germany	159	20	17	32
Russian Federation	144	22	31	16
South Korea	141	17	20	39
Canada	92	13	18	16
Ukraine	85	13	15	48
United Kingdom	69	11	19	18
Sweden	65	9	10	52
World Total	2658	370	437	16

a nuclear chain reaction: in May 1939 and 1940 they patented the principles of what was to become both the nuclear reactor and the atomic bomb. At the same time they also predicted many other applications of radioactivity both for industrial and medical purposes. The French are still proud of this paternity of nuclear power, even though, due to World War II, the first nuclear reactor, Enrico Fermi's CP1, was actually built in the USA and went critical in December 1942 when France was occupied. As soon as October 1945, when France was just starting to recover from the war, the provisional government presided by General de Gaulle created the French Commissariat à l'Énergie Atomique, CEA, with a mission to develop all aspects of the new energy source. The first French experimental reactor, Zoé, started operation in December 1948.

5.3.3 From 1945 to 1973: "The glorious thirty years"

During the 50s, a period of vigorous post war reconstruction (helped by the Marshall Plan), France relied mostly on its domestic coal resources which supplied more than two thirds of its energy consumption. But during this period, the newly integrated national utility Électricité de France, EDF, was engaged in a grand endeavour, the equipment of France in hydropower: as early as 1960, hydropower was delivering 40 TWh, 60% of the French electricity consumption. By the 70s, all potentially economical hydraulic sites, both mountain and run-of-the-mill river dams had been built. EDF had even built the world's first and still unique tidal power plant (La Rance).

In 1957, two significant events occurred: following the Suez Anglo-Israeli-French expedition, France experienced during a few months an oil embargo from the Arab countries, an embargo still remembered in 1973, and at the same period the first and only significant natural gas deposit began production in Lacq, near Bordeaux. The resources were large but the gas contains 10% CO_2 and 16% hydrogen sulphide which is toxic and highly corrosive. Still the Lacq natural gas will replace all the previous "gaz de ville" made from coal at the outskirts off all major French town. Production was to peak in 1982: the French network of gas pipes is now fed with gas imported from Norway, Algeria and Russia.

As domestic coal production had been severely declining since 1963, by 1973 two third of the French energy consumption and 68% of the French electricity consumption came from oil, cheap oil imported mainly from the Middle-East.

5.3.4 The first generation of nuclear plants

As early as 1946, some uranium was discovered in France by the CEA, but France did not master the technology of isotopic enrichment, still a US monopoly at the time. Consequently, the French designed, developed and deployed a first generation of nuclear power plants which did not require enriched uranium as a fuel: the so-called UNGG (for Uranium Naturel Gaz Graphite), similar to the British Magnox. The very first nuclear electricity was generated in France in October 1956, in G1, an experimental reactor operated by the CEA. But the first commercial nuclear plant operated by EDF, the 70 MWe UNGG "Chinon A1", began generating power feeding the French grid in 1963.

The spent fuel from Magnox and UNGG reactors cannot be stored very long under water and must be reprocessed to stabilize the High Level radioactive waste it contains. The French therefore developed the reprocessing technology, recovering the residual uranium and the plutonium contained in the spent UNGG fuel. Anticipating a vigorous increase for nuclear electricity production, it was then thought that the plutonium would very soon be needed to fuel the Fast Neutron Breeder FBR, a type of reactor which technically is more complex but can extract energy from uranium much more efficiently. Logically enough, the French realised in 1973 the first actual breeder, the 250 MWe demo FBR, Phénix, still operating today (the plant is due to be shutdown in 2009 and then will be decommissioned).

By 1970, EDF was operating 6 UNGG plants, an experimental heavy water gas cooled plant (with the CEA) and, together with Belgium, a 300 MWe PWR, Chooz A1. The capacity of the plants (totalling 3 GWe) supplied 8% of the French electricity consumption. At a time when each new nuclear power plant in the western world was a unique prototype, EDF had notably taken the very unusual decision to order its last two plants as identical twins (in fact it was a series of three identical plants, the third one of this kind being built in Spain). This decision marks the first stage of what will become a main characteristic of the French industrial policy: increasing exploitation efficiency through standardisation.

In the meantime, the CEA had developed the gaseous diffusion technology to enrich uranium for Defence programs. Over the world, most utilities were now buying Light water plants, PWR and BWR of American technology. LWRs are far more compact than UNGG, which results in lower capital costs, but they require a fuel enriched to 3 to 4% ^{235}U.

So, in 1970, EDF took the first momentous decision to discontinue the "French" reactors series, and to acquire LWRs from US origin from then on. The US enrichment monopoly having been broken was no longer a political issue. The French company Framatome acquired the PWR license from Westinghouse while Compagnie Générale d'Electricité took the GE license for BWR. EDF was planning on ordering from either company about one 900 MWe LWR per year, starting with 2 PWR in Fessenheim and 1 PWR in Le Bugey. Consequently, CEA started adding a new Head-end to its La Hague commercial reprocessing plant to accommodate much more radioactive LWR spent fuel.

5.3.5 Reacting to the first oil shock

Even though the first oil shock – multiplication by a factor of 4 of the oil prices decided by OPEC in the wake of the 1973 Kippur War – was severely resented in most western countries, it was especially problematic in France for two reasons. On the one hand, oil was supplying more then two third of our electricity, a commodity even more vital than gasoline, and on the other hand memories of the 1957 embargo were still vivid in many French minds. Overnight, the previously soft addiction to imported oil became unacceptable and something had to be done to reduce it. As there was – and unfortunately still is – little possibility of substitution to oil products for transportation, efforts were decided on energy conservation and phasing oil out of electricity generation.

After consultation with EDF, the government, under Prime Minister Pierre Messmer, decided in March 1974 to cancel all the planned fossil power plants and accelerate dramatically the nuclear equipment programme, jumping from 1 or 2 to 6 plants a year, with a clear-cut objective: replacing totally oil by nuclear power in the French electricity mix! Furthermore, in 1975, it was decided to select only one plant type, the standardized 900 MWe PWR built by EDF with the Nuclear Island NSSS supplied by Framatome under license from Westinghouse. In February 1974 was also launched the construction of the large international EURODIF enrichment plant on the Tricastin site, based on the CEA technology and able to supply enriched fuel to 100 LWR. Framatome, therefore, gained the monopoly of NSSS supply to the whole French nuclear programme. Westinghouse was then asked to sell its shares in the capital of Framatome to the CEA, part of it being paid in kind through a common R&D programme (Framatome is now AREVA NP).

5.3.6 From 1974 to 2000: The French "quantitative" nuclear programme

Launched in 1974, the second generation of nuclear power plants owned and operated by EDF was unique in its scope and degree of standardization. It comprised 6 series of PWR units:

- 6 "CP0" 900 MWe Plants (including the first 3 ordered before 1974)
- 18 "CP1" 900 MWe Plants
- 20 "CP2" 900 MWe Pants
- 6 "P4" 1300 MWe Plants
- 14 "P'4" 1300 MWe plants
- 4 "N4" 1450 MWe Plants

As a matter of fact, all 34 CPx units identical NSSS and differ only in the non-nuclear balance of plant BOP. The same applies to P4 and P'4.

This high degree of standardization allowed a drastic cost reduction along the series CP and P. The N4 series was too short to exhibit any significant series effect.

Table 5.3.2 French Nuclear Power Plants in operation and in construction.

Unit name	*Type*	*Series*	*Rating (MWe)*	*Construction*	*Operation*
Phénix (CEA)	*FBR*		250	1968	1973
Fessenheim 1	PWR	CP0	880	1971	1977
Fessenheim 2	PWR	CP0	880	1972	1977
Bugey 2	PWR	CP0	910	1972	1978
Bugey 3	PWR	CP0	910	1973	1978
Bugey 4	PWR	CP0	880	1974	1979
Bugey 5	PWR	CP0	880	1974	1979
Tricastin 1	PWR	CP1	915	1974	1980
Tricastin 2	PWR	CP1	915	1974	1980
Dampierre 1	PWR	CP1	890	1975	1980
Dampierre 2	PWR	CP1	890	1975	1980
Gravelines B1	PWR	CP1	910	1975	1980
Gravelines B2	PWR	CP1	910	1975	1980
Gravelines B3	PWR	CP1	910	1975	1980
Dampierre 3	PWR	CP1	890	1975	1981
Dampierre 4	PWR	CP1	890	1975	1981
Tricastin 3	PWR	CP1	915	1975	1981
Tricastin 4	PWR	CP1	915	1975	1981
Gravelines B4	PWR	CP1	910	1976	1981
Saint-Laurent B1	PWR	CP2	915	1976	1981
Saint-Laurent B2	PWR	CP2	915	1976	1981
Blayais 1	PWR	CP1	910	1977	1981
Blayais 2	PWR	CP1	910	1977	1982
Chinon B1	PWR	CP2	905	1977	1982
Chinon B2	PWR	CP2	905	1977	1983
Blayais 3	PWR	CP1	910	1978	1983
Blayais 4	PWR	CP1	910	1978	1983
Cruas 1	PWR	CP2	915	1978	1983
Cruas 2	PWR	CP2	915	1978	1984
Paluel 1	PWR	P4	1330	1977	1984
Paluel 2	PWR	P4	1330	1978	1984
Cruas 3	PWR	CP2	945	1979	1984
Cruas 4	PWR	CP2	915	1979	1984
Gravelines B5	PWR	CP1	910	1979	1984
Flamanville 1	PWR	P4	1330	1979	1985
Gravelines B6	PWR	CP1	910	1979	1985
Paluel 3	PWR	P4	1330	1979	1985
Saint-Alban 1	PWR	P’4	1335	1979	1985
Cattenom 1	PWR	P’4	1300	1979	1986
Saint-Alban 2	PWR	P’4	1335	1979	1986
Chinon B3	PWR	CP2	905	1980	1986
Flamanville 2	PWR	P4	1330	1980	1986
Paluel 4	PWR	P4	1330	1980	1986
Belleville 1	PWR	P’4	1310	1980	1987
Cattenom 2	PWR	P’4	1300	1980	1987
Belleville 2	PWR	P’4	1310	1980	1988
Chinon B4	PWR	CP2	905	1981	1987
Nogent 1	PWR	P’4	1310	1981	1987
Nogent 2	PWR	P’4	1310	1982	1988
Cattenom 3	PWR	P’4	1300	1982	1990

(*Continued*)

Table 5.3.2 (Continued)

Unit name	*Type*	*Series*	*Rating (MWe)*	*Construction*	*Operation*
Golfech 1	PWR	P'4	1310	1982	1990
Penly 1	PWR	P'4	1330	1982	1990
Cattenom 4	PWR	P'4	1300	1983	1991
Penly 2	PWR	P'4	1330	1984	1992
Golfech 2	PWR	P'4	1310	1984	1993
Chooz B1	PWR	N4	1500	1984	1996
Chooz B2	PWR	N4	1500	1985	1997
Civaux 1	PWR	N4	1495	1988	1997
Civaux 2	PWR	N4	1495	1991	1999
Flamanville 3	PWR	EPR	1600 MW	2007	2012 (forecast)

An additional cost reduction came from building systematically several units (2 to 6) along one another on the same site. Standardization allows also a very efficient return of experience because any lesson learned on one unit is completely suitable to be applied on all its identical twins. Standardization facilitates the training of operation and maintenance teams who can move from one plant to the other without losing their efficiency.

On the other hand, going standardized was a bold decision because of the risk of common mode failure… And some such failures did happen, but only in the process of ageing: they could therefore be repaired during the normal periodical outages before each unit reached the "critical age" for a given defect to appear.

The huge planned construction program allowed Framatome to invest in very modern construction plants and facilities, dimensioned to accommodate eight NSSS per year, including two for potential exports. These modern facilities allowed reducing fabrication costs by fully taking advantage of the standardization: what could be called a "virtuous" circle.

With the connection of Civaux 2, the last of the N4 series to the grid, the "quantitative program" was completed in 2000.

The first 900 series were actually plants built under license, duplicated from an existing "lead plant" already operating in the United States. But after 1974, in stark contrast to the French situation, the US nuclear program ran into deep troubles (which are beyond the scope of this paper). As a result, Paluel 1, the first of the P4 series, had to be completed far in advance of South Texas 1, its supposed "lead plant". Westinghouse was no longer in a position to act as a true licensor, and Framatome terminated prematurely the license agreement in early 1981. From then on, the PWR technology was recognized to be entirely "naturalized French", and the N4 technology is genuinely French.

Table 5.3.2 recapitulates the main features of the French NPP in operation and in construction.

5.3.7 A comprehensive systemic approach to nuclear power

Other countries have progressively adopted the French approach of building, step by step, series of standardized plants. But what makes the French approach rather unique in the western economies is its comprehensiveness. It was really a systemic (some would say "holistic") approach, developing the whole fuel cycle in parallel to and in cohesion with the nuclear power plant construction program.

While EDF and Framatome were busy building the plants, the CEA, then its industrial subsidiary COGEMA (now AREVA NC), established in 1976 as a fully owned subsidiary of CEA, was exploring and mining uranium, building the EURODIF enrichment plant and expanding the capacity of the La Hague reprocessing plant. CEA developed the vitrification process to immobilize the high level waste extracted from the spent fuel and facilitate first their storage then their disposal. This vitrification technology is still today mastered by very few countries, to say the least.

Furthermore, as already mentioned, the French had the vision of a long-term "sustainable" nuclear power and the CEA was leader in developing the fast breeder technology. After the Phénix demo plant, EDF and some European utilities ordered in 1977 Superphénix, a 1200 MWe Prototype FBR to be built on the Creys-Malville site on the Rhône River. Even though prematurely shut down for political reasons in 1998, Superphénix remains the largest such breeder plant to have operated anywhere.

By 1985, when it became clear that the nuclear development in the world was much less fast than what was anticipated in the 70s, the early deployment of breeder plants was no longer urgent. The French decided then to recycle the plutonium extracted from the spent PWR fuel assemblies and previously earmarked for the FBR program in the PWR plants as "MOX" fuel. The firs unit, St Laurent B1, was loaded with MOX in 1987 and now, 20 units are routinely using 30% MOX assemblies at each reload. The capacity of the La Hague plants allowed to recycle also spent fuel for other customers: a closed cycle being recognized as a very efficient way to manage the spent fuel both in consideration to fissile resources preservation and in consideration to efficient final waste depositories.

The only unresolved issue that remained is the final disposal of long-lived radioactive waste. This topic has been dealt with systematically by public authorities under the responsibility of the French parliament. A first law voted in 1991 for duration of 15 years has been achieved to organise research on 3 major axes: separation and transmutation, geological disposal, interim storage. After evaluation of the results (done by an independent body, the "Commission Nationale d'Evaluation" – CNE) a new law was voted (28 June 2008) and establish the main orientations for the management of all the nuclear matters and for nuclear wastes, through a national plan to be updated every 3 years.

The closed fuel cycle is considered as the reference way for managing spent fuel. All the radioactive wastes have to be properly conditioned and must find a specific storage. Standardization of the packaging through "universal canisters", both for vitrified and compacted residues is part of an efficient solution. For high activity and long (HAVL) nuclear wastes, final geological disposal is presented as the nominal option.

2012 will be the date for a technical review among the different options for transmutation solutions. These solutions are in relation with the decision to promote the conception then the realisation of a prototype of a fast neutron plant which will have a capacity to burn actinides.

For geological disposal, the 2006 law confirms the general orientations already taken but introduces now the concept of reversibility. The formal demand of authorisation for the storage will be analysed in 2015 and beginning of exploitation is expected in 2025.

All these modalities remain under the control of the French Parliament; scientific evaluation continues to be done by the CNE. Special attention is paid to public debate through the creation of local committees for public information and follow-up.

5.3.8 Preparing for the renewal of the PWR fleet

Even if, globally, the French nuclear fleet is quite young, EDF has begun to prepare the conditions of the renewal of his PWR fleet. The EPR nuclear plant has been designed for this renewal.

This design takes into account all the previous experience, not only of the French nuclear programme but also of the German realisations (French N4 series as far as Germany's Konvoi design). In particular the safety authorities of both countries have strongly interacted to take advantage of the innovations and conceptual dispositions of the fleets in operation. Nearly all the European utilities have been involved to express common requirements. Evidently the conception of the EPR includes the return of experience of all the incidents and accidents so long as they justify new approaches and solutions improving safety and providing new margins for operational purposes. This includes significant progress in economics, and reduction in radioactive waste. Its level of safety is particularly high, including systems backed up in quadruple and the ability to provide a range of solutions for scenarios of total safety function loss or to contain a melt-down, even if there is a very low probability of that occurring. The EPR has also been designed to be exceptionally resistant to outside aggressions, such as the impact of large commercial aircraft.

EPRs are being built at two sites, one in Olkiluoto, Finland and the other in Flamanville, France. Many other projects have been already finalised or are under discussion with customers all other the world.

EPR is considered as the reference solution for the renewal of the French PWR Fleet; the modalities of that renewal (number of plants, calendar for replacements, localisation etc.) will be adapted to the energy demand but also in good adequacy to the life-extension programme.

This renewal will also take into account the opportunity (or the necessity) to introduce FBR for a better management of fissile resources. Such an opportunity shall be considered as far as this kind of GEN IV plants will reach an industrial maturity. The decision to operate an industrial prototype around 2020 represents a key event on that path.

5.3.9 2001: Enters AREVA

The achievement of the French nuclear fleet gives the opportunity to develop a complete nuclear industry for design of nuclear plants, exploitation and services, nuclear fuel cycle management, logistics, etc. AREVA, created in 2001, is the industrial heir of 50 years of research, technological innovations and industrial realisations in nuclear equipments and services.

Through its Front end division, Back end division and Reactors and services division, the AREVA group operates in every area of the nuclear cycle.

In the front end of the cycle, AREVA supplies uranium and offers the conversion and enrichment services needed to fabricate the fuel assemblies that go into the reactor core. In the Reactors and Services division, the group has the expertise in all the processes and technologies needed for reactor design, construction, maintenance and continuous performance improvement. AREVA focuses principally on the PWR and BWR markets. Research and development programmes are going on about other technologies as HTR and chiefly sodium FBR in relationship with the CEA within international cooperation, such as GEN IV initiative.

The Front End division's operations include uranium ore exploration, mining and concentration of uranium as U_3O_8 into uranium hexafluoride (UF_6), uranium enrichment, and nuclear fuel design and fabrication.

The Reactors and services division is in charge of nuclear power plant design, construction and modernization, nuclear power plant equipment supply, and nuclear services, particularly for scheduled reactor outages.

The Back End division focuses on used fuel treatment and recycling, design and fabrication of casks for the transportation and storage of nuclear materials, and nuclear materials transportations and logistics.

In summary, the group has now in capacity to:

- sell uranium to its utility customers,
- supply uranium processing services to produce fuel, and design and fabricate fuel assemblies (for PWR and BWR as for experimental research reactors),
- design and build power plants and provide life extension services,
- offer engineering services and equipment to optimize power plant performance,
- recycle its customers' used fuel to recover reusable materials (uranium and plutonium), produce MOX fuel from these recovered materials, treat and package in standardized canisters the ultimate waste for safe disposal.

5.3.10 Conclusion

For nearly 50 years France has developed a comprehensive programme which provides nearly 80% of its electricity without CO_2 emissions. This policy has also given the opportunity to create a strong and complete nuclear industry from mining to waste management, including all the aspects of nuclear plants design and services to utilities. The global nuclear renaissance, due to increasing demand and new environmental issues, gives the opportunity to take advantage of the success story of the French nuclear programme, to diversify the number of customers all over the world and to open new partnerships.

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www.andra.fr	nuclear waste management in France
www.cea.fr	nuclear research in France
www.irsn.org	French nuclear safety and radiological protection
www.sfen.org	French nuclear society
www.areva.com	nuclear fuel cycle, nuclear plants technologies
www.edf.fr	nuclear electricity production

Colour plates

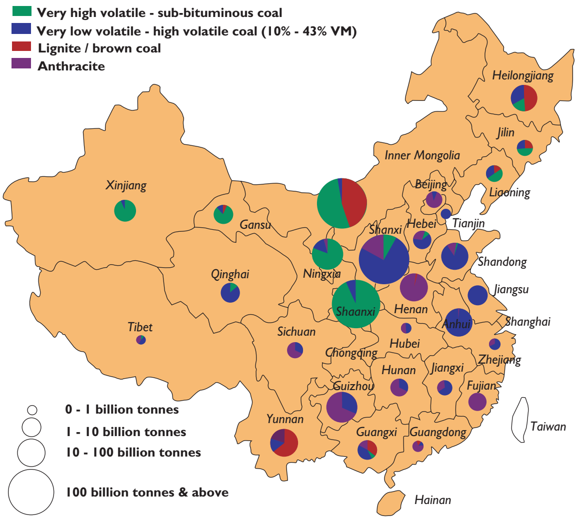

Plate 1 Location of China's coal resources.

Source: Beijing HL Consultant, 2006.

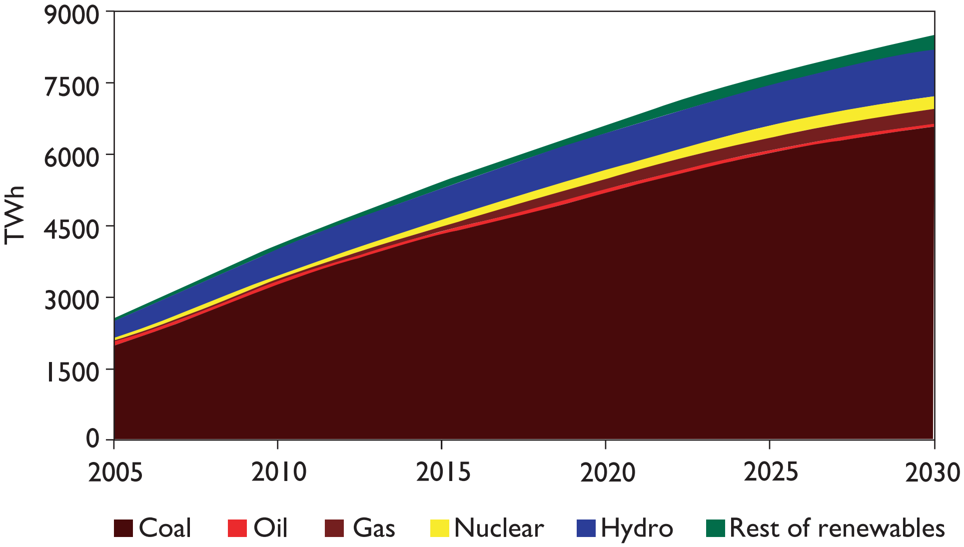

Plate 2 Projected electricity generation in China, 2005–2030.

Source: World Energy Outlook, 2007, p. 345.

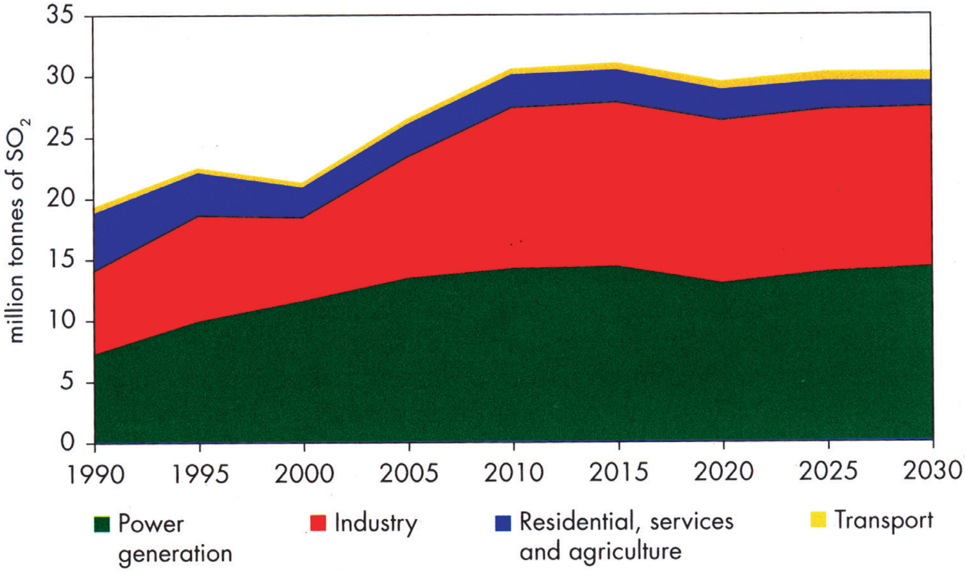

Plate 3 Sulphur dioxide emissions, sector-wise.

Source: World Energy Outlook, 2007, p. 311.

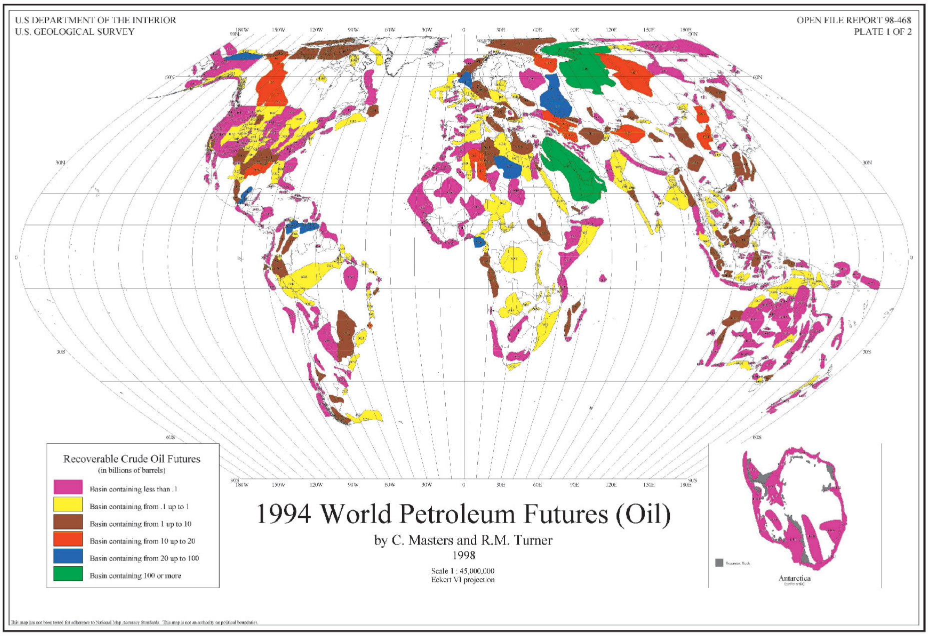

Plate 4 Geological provinces (128) in different countries (96) in the world and the estimated petroleum resource in each of the province (Masters et al., 1998).

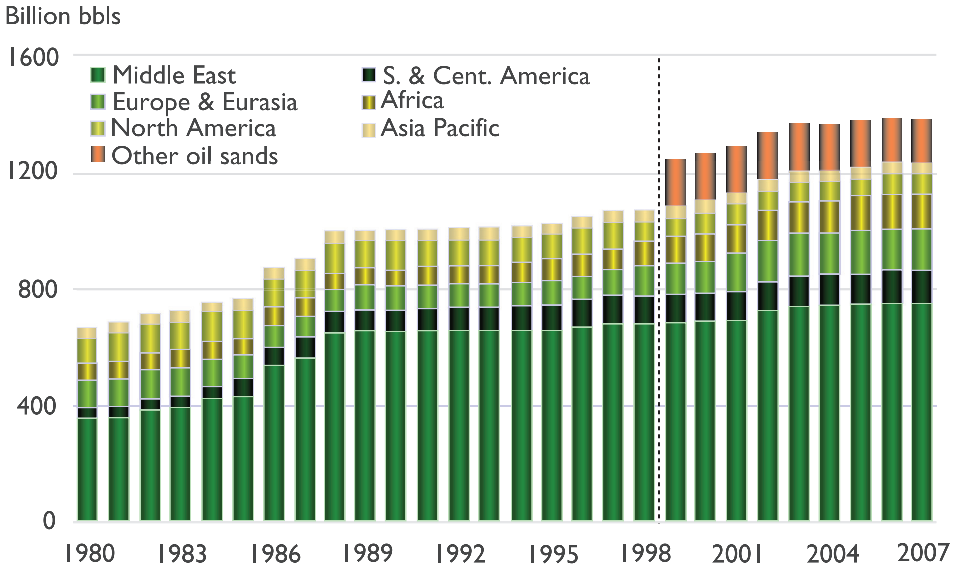

Plate 5 Changes in global oil reserves from 1980 to 2007 (BP, 2008).

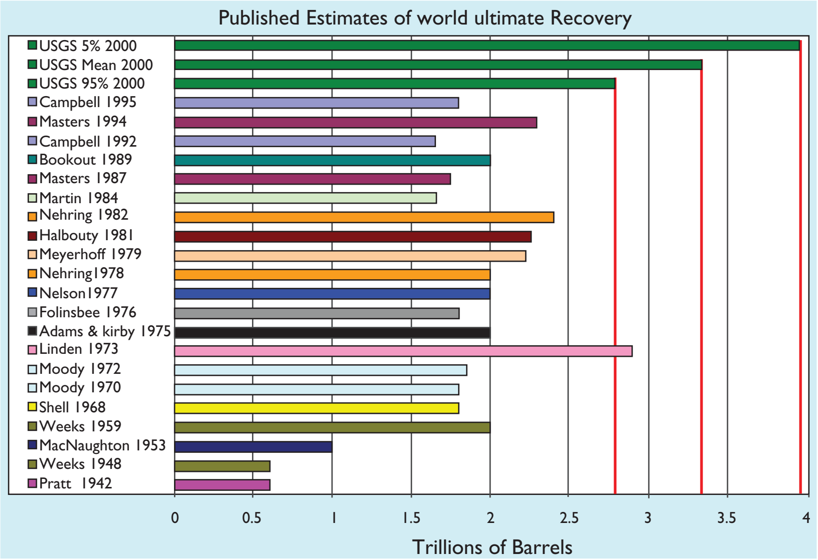

Plate 6 Past estimates of world ultimate oil resources (Caruso, 2005).

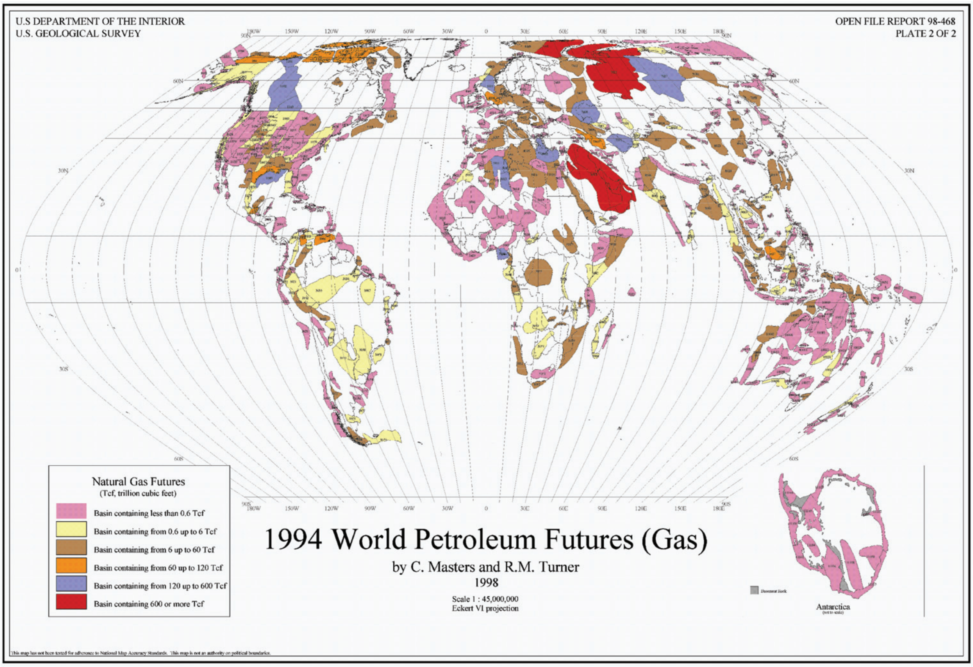

Plate 7 Geological provinces in the world and the estimated natural gas resource in each of the province (Masters et al., 1998).

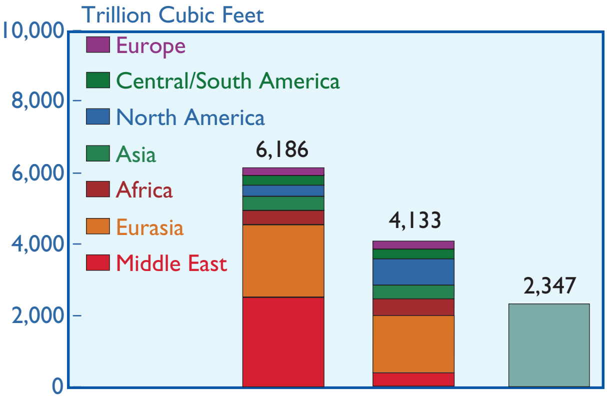

Plate 8 World natural gas resources by geographic region (EIA, 2008).

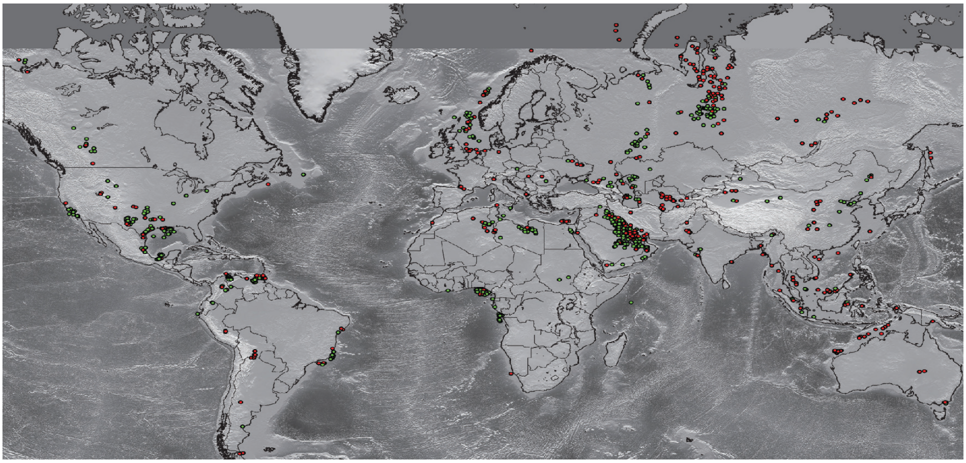

Plate 9 Distribution of Giant oil fields in the world, indicating two strong clusters in Arabian Gulf and Siberian Basin (Mann et al., 2007).

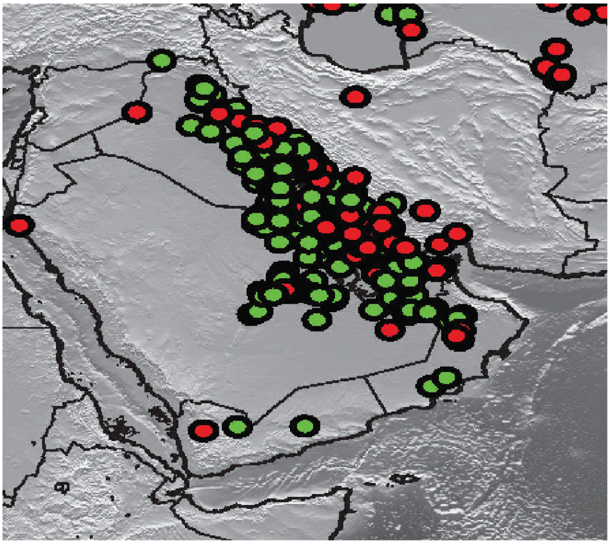

Plate 10 Clustered distribution of Giant oil fields in the Arabian Gulf region (Mann et al., 2007).

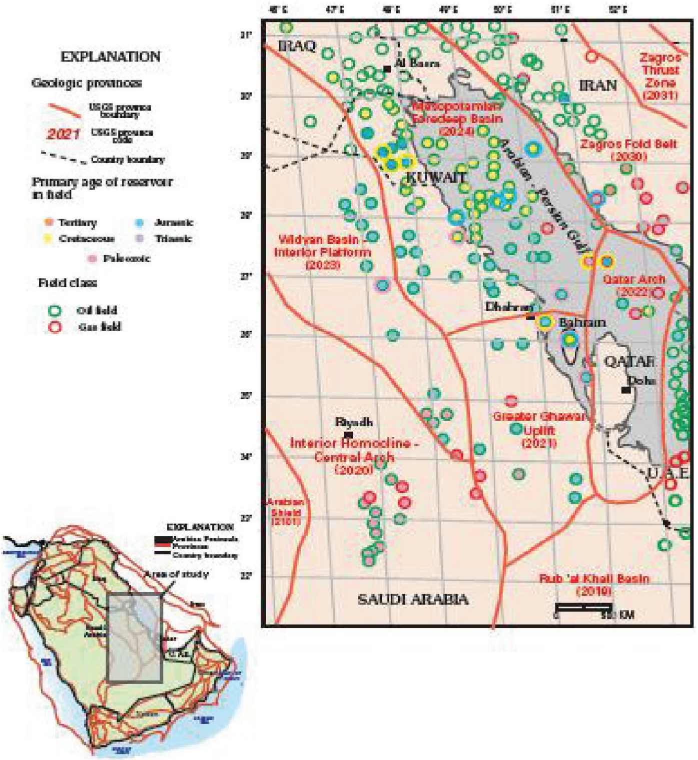

Plate 11 USGS geologic provinces (2010, 2020, 2021, 2023, 2024) and oil/gas fields of central and northern Arabian-Persian Gulf (Pollastro, 2003).

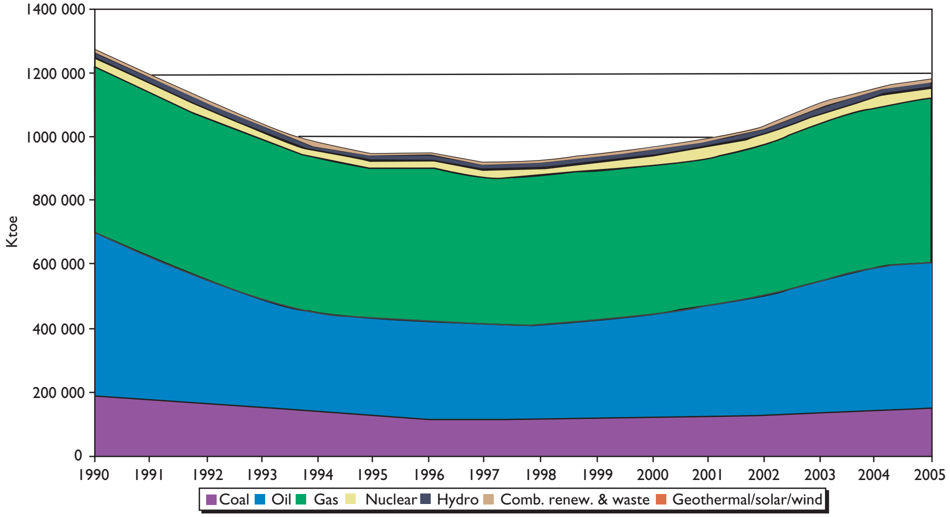

Plate 12 Evolution of total production of energy in Russia from 1990 to 2005 (IEA, 2007).

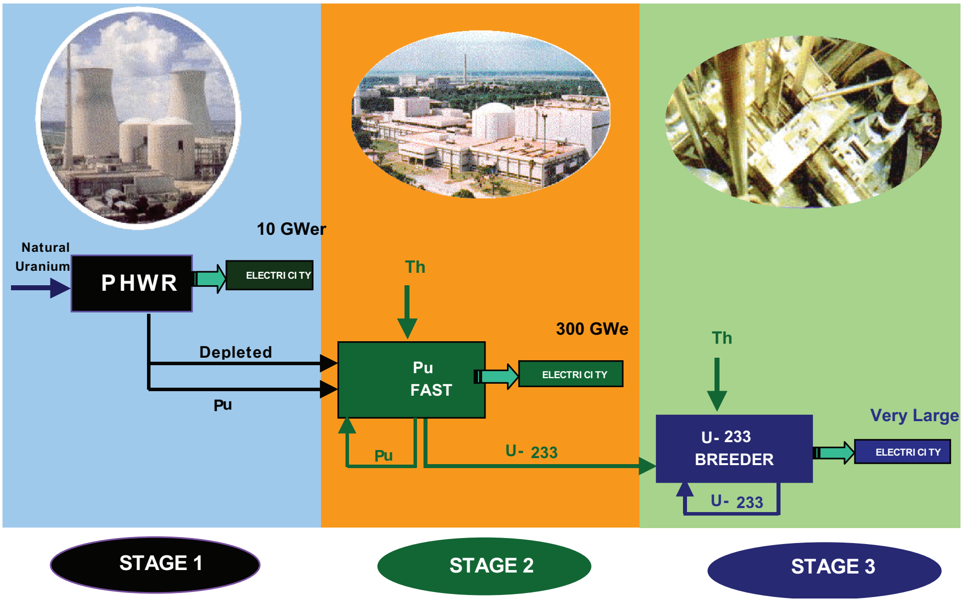

Plate 13 Three-stage nuclear power programme.

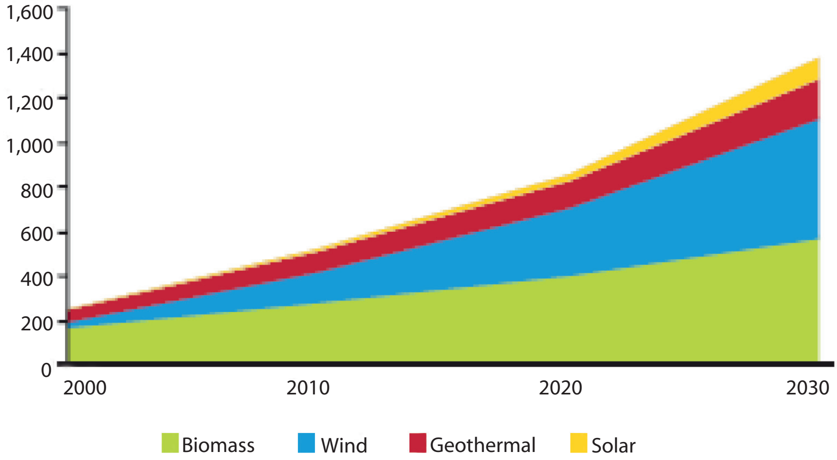

Plate 14 Evolution of renewables.

Source: United Nations, WEA, 2006.

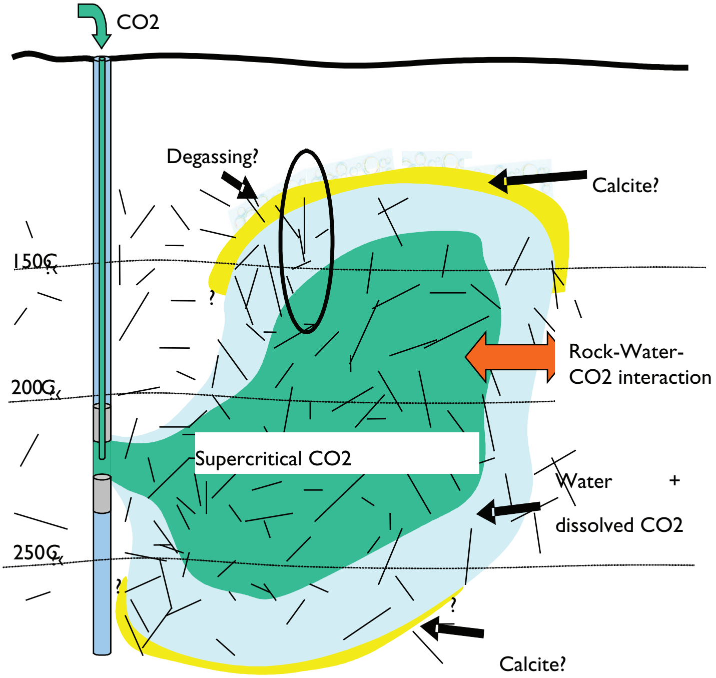

Plate 15 Concept of CO_2 sequestration in geothermal fields.

Appendix

Prefix names of multiples and submultiples

Prefix	*Symbol*	*Factor by which unit is multiplied*
Exa	E	10^{18}
Peta	P	10^{15}
Tera	T	10^{12}
Giga	G	10^{9}
Mega	M	10^{6}
Kilo	k	10^{3}
Hecto	h	10^{2}
Deka	dk	10^{1}
Deci	d	10^{-1}
Centi	c	10^{-2}
Milli	m	10^{-3}
Micro	μ	10^{-6}
Nano	n	10^{-9}
Pico	p	10^{-12}

Conversion of older units into SI units

Quantity	*SI unit*	*Old unit*	*Value of old unit in SI unit*
Force	Newton (N)	Dyne	10^{-5} N
Pressure	Pascal (Pa)	Atmosphere	1.013×10^{5} Pa
Energy	Joule (J)	Calorie	4.184 J

1 bar = 10^{6} dynes/cm^{2} = 750 torr = 14.504 lb/in^{2}

1 BTU (British Thermal Unit) = 1.055×10^{3} Joules (J)
1 erg = 1 dyne/cm = 2.39×10^{-8} calorie = 1×10^{-7} Joules = 9.4805×10^{-11} BTU
1 watt = I Joule per second
Fuel value of 1 m^{3} of fuelwood = 9.4 gigajoules (GJ)
Fuel value of 1 t of coal = 28.9 GJ
Fuel value of 1 t of oil = 1.44 t of bituminous coal
1 toe = tonne of oil equivalent = 41.868 GJ = 10^{7} kcal

I U.S. gallon = 3.875 L; 1 Imperial gallon = 4.546 L
1 barrel (crude oil) = 42 U.S. gallons = 38.50 Imp. Gallons = 162.75 L
1 acre-ft = 326,000 gallons

1 hectare (ha) = 100 m × 100 m = 10^4 m^2 = 2.47 acres
1 cu · km (km^3) = 10^3 ha · m; 1 ha · m = 8.1 acre-ft

The following information is drawn from "World Energy Outlook 2007", International Energy Agency, Paris, 2007, pp. 633–641.

General Conversion factors for Energy

To	*TJ*	*Gcal*	*Mtoe*	*MBtu*	*GWh*
From	*multiply by*				
TJ	1	238.8	2.388×10^{-5}	947.8	0.2778
Gcal	4.1868×10^{-3}	1	10^{-7}	3.968	1.163×10^{-3}
Mtoe	4.1868×10^{4}	10^{7}	1	3.968×10^{7}	11630
MBtu	1.0551×10^{-3}	0.252	2.52×10^{-8}	1	2.931×10^{-4}
GWh	3.6	860	8.6×10^{-5}	3.412	1

TJ = Tera Joules; Gcal = Gigacalories; Mtoe = Million tonnes of oil equivalent
MBtu = Million British Thermal Units; GWh = Gigawatt hours

1 million tonnes of oil equivalent = 1.9814 million tonnes of coal
= 0.0209 million barrels of oil/day
= 1.2117 billion cubic metres of gas

Conversion factors for mass

To	*kg*	*t*	*lt*	*st*	*lb*
From	*multiply by*				
kilogramme (kg)	1	0.001	9.84×10^{-4}	1.102×10^{-3}	2.2046
tonne (t)	1000	1	0.984	1.1023	2204.6
long ton (lt)	1016	1.016	1	1.120	2240.0
short ton (st)	907.2	0.9072	0.893	1	2000.0
pound (lb)	0.454	4.54×10^{-4}	4.46×10^{-4}	5.0×10^{-4}	1

Conversion factors for volume

To	*gal U.S.*	*gal U.K.*	*bbl*	*ft^3*	*L*	*m^3*
From	*multiply by*					
U.S. gallon (gal)	1	0.8327	0.02381	0.1337	3.785	0.0038
U.K. gallon (gal)	1.201	1	0.02859	0.1605	4.546	0.0045
Barrel (bbl)	42.0	34.97	1	5.615	159.0	0.159
Cubic foot (ft^3)	7.48	6.229	0.1781	1	28.3	0.0283
Litre (L)	0.2642	0.220	0.0063	0.0353	1	0.001
Cubic metre (m^3)	264.2	220.0	6.289	35.3147	1000.0	1