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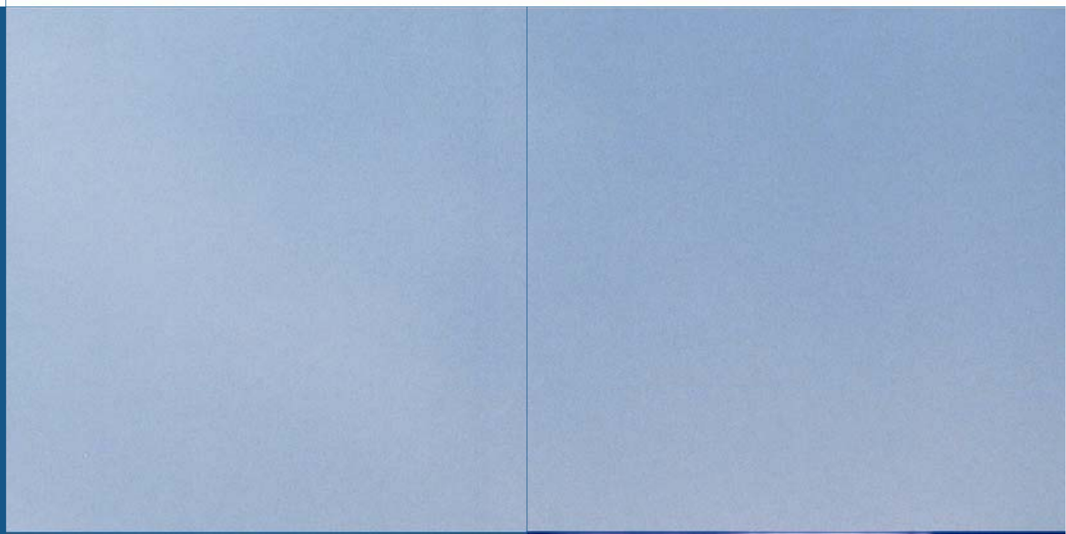
2007 Survey of Energy Resources

World Energy Council 2007

Promoting the sustainable supply and use of energy for the greatest benefit of all



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Officers of the World Energy Council

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Foreword

This, the 21st edition of the World Energy Council's *Survey of Energy Resources* (SER), is the latest in a long series of reviews of the status of the world's major energy resources. It covers not only the fossil fuels but also the major types of traditional and novel sources of energy.

The *Survey* is a flagship publication of the World Energy Council (WEC), prepared triennially and timed for release at each World Energy Congress. It is a unique document in that no entity other than the WEC compiles such wide-ranging information on a regular and consistent basis. This highly-regarded publication is an essential tool for governments, NGOs, industry, academia and investors.

The WEC is grateful to all those Member Committees, institutions and specialists who have contributed their expertise and data to this *Survey*.

Special thanks go to Professor Nada Zupanc, Chairman of the SER Executive Board, to Dr Robert Schock, Director of Studies, to the Studies Committee for guiding the production of the Survey and to Mr Valli Moosa, Chairman of Eskom, for providing an exceptionally perceptive Overview.

Finally the WEC thanks the Joint Editors Judy Trinnaman and Alan Clarke for compiling, validating and formatting the data. Once again they have successfully and professionally completed this enormous task, both achieving an excellent quality and keeping to the planned schedule. The WEC is grateful to them for their knowledge, dedication, tenacity and inspiration.

C.P. Jain
Chair WEC Studies Committee

Introduction

This 21st WEC *Survey of Energy Resources* contains a chapter for each energy resource, ranging from the conventional fossil fuels to the renewables, both new and traditional. Generally, the coverage of each resource comprises a Commentary by a leading expert in the field, followed by Definitions, Tables and Country Notes. The tables summarise the worldwide resources, reserves, production and consumption of fossil fuels and comparable data for non-fossil energy sources, as applicable. The Country Notes aim to highlight the main features of the resource and its utilisation.

- Reserves/Resources - where relevant, tables of fossil fuels provide reserve statistics (covered globally from WEC and non-WEC sources) and amounts in place (as reported by the WEC Member Committees);
- Tabulations - data tables are arranged on a standard regional basis throughout;
- Units - where relevant, data have been provided in alternative units (cubic feet as well as cubic metres, barrels as well as tonnes) in order to facilitate use of survey data in an industry context;
- References and Sources - as far as possible, these have been consolidated in introductory notes to the data tables and country notes, or appended to the commentaries on each resource.

Any review of energy resources is critically dependent upon the availability of data and reliable, comprehensive information does not always exist. While the basis of the compilation is the input provided by the WEC Member Committees, completion necessitates recourse to a multitude of national and international sources and, in some cases, to estimation. Difficulties in obtaining information continue to be compounded by trends in the energy sector. As further deregulation and privatisation take place, the availability of data tends to be reduced as some data-reporting channels may be lost or specific items become confidential. Moreover, problems in the quantification of energy resources persist, in particular for those universally-found resources: solar energy, wind power and bioenergy, owing to their evolutionary status and generally decentralised nature.

Notwithstanding the efforts of the UN/ECE Ad Hoc Group of Experts to codify and standardise the terminology of reserves and resources reporting (UN Framework Classification for Fossil Energy and Mineral Resources), it remains a fact that, at the present time, almost every country that possesses significant amounts of mineral resources has developed its own unique set of expressions and definitions. Whilst the UN continues its work on harmonisation of the terminology, it will take some considerable time before the theory can be applied globally. It is customary for national-level reserves and resources to be reassessed only infrequently. The improvement in reporting will thus occur gradually over a period of time as reassessments are undertaken and subsequently reported on a codified basis. In the meantime, the resources and reserves specified in the present *Survey* conform as far as possible with the established definitions specified by the WEC. It is a matter of judgement for each member country to determine which, among the available assessments of resources and reserves, best meet these definitions. A similar approach has been followed for non-reporting countries, for which the Editors have selected the levels of reserves which, in their opinion, are most appropriate.

This *Survey* is testament to the effect of a raised oil price and increasing concern with aspects of climate change and energy sustainability. Resources and technologies that were previously uneconomic to develop are now seeing enhanced R&D, with many schemes being implemented or approaching fruition.

Particular points of emphasis in the present *Survey*:

- coverage of fossil fuel reserves, particularly in respect of coal, has been improved by establishing the recoverable portion of the in-place quantities in a number of countries where this had not been previously reported;
- wood energy has been included with other biofuels;
- coverage of oil shale, natural bitumen, solar/PV, wind energy and the marine technologies has been expanded and improved to reflect their changing prospects.

As Editors, we strive to develop and maintain contacts in the energy world and hope that in time the availability of data will not only improve but expand to cover those energy resources that presently go unrecorded (or under-recorded).

We are grateful to all those who have helped to produce this *Survey*: we extend our thanks to the WEC Member Committees, to the authors of the Commentaries, to Nada Zupanc, Bob Schock and the Studies Committee for guiding the production of the Survey and to Valli Moosa for contributing the Overview.

Judy Trinnaman and Alan Clarke
Editors

Overview

> "Energy is essential for development, yet two billion people currently go without, condemning them to remain in the poverty trap. We need to make clean energy supplies accessible and affordable. We need to increase the use of renewable energy sources and improve energy efficiency. And we must not flinch from addressing the issue of over consumption - the fact that people in the developed countries use far more energy per capita than those in the developing world" (Kofi Annan, Secretary General, United Nations.)

Introduction

The availability of energy resources is of paramount importance to society. This new World Energy Council *Survey of Energy Resources* addresses the question of future availability at a critical time in the development of global economies and the people who depend on them. The fundamental dilemma facing us is that energy is a vital ingredient for growth and sustainable development, and for the vast majority of economic activities, but that energy production and use contribute to global warming. The greatest challenge facing the energy sector today is how to meet rising demand for energy, whilst at the same time reducing our emissions of greenhouse gases. Climate change is undoubtedly an imperative which must be addressed with a sense of urgency. We need to find new and innovative ways of addressing mitigation of greenhouse gases as well as adapting to changes in the climate. Given that the energy sector is critical to the functioning of most economies, is long term in nature and is very vulnerable to the negative impacts of climate change, this issue should be at the top of everyone's agenda.

Resources are the backbone of every economy. In using resources and transforming them, capital stocks are built up which add to the wealth of present and future generations. However, the dimensions of our current resource use are such that the chances of future generations having access to their fair share of scarce resources are endangered. We therefore need to ensure the sustainable use of our natural resources through the creation of a long-term sustainable base and much greater focus throughout the energy value chain.

Access to energy and security of supply

Lack of access to energy hampers economic and social development in many regions and is an obstacle to the achievement of social, environmental and economic progress worldwide. Access to reliable, affordable commercial energy provides the basis for heat, light, mobility, communications and agricultural and industrial capacity in modern society. Energy is important for development as is demonstrated in consumption trends – notably, the increase foreseen in energy demand, for example the International Energy Agency estimates an increase of 60% by 2030, (World Energy Outlook, 2002). This increasing demand will have to be met by a complex mix of energy resources in order to meet a wide variety of energy needs, whilst considering environmental and other constraints. Meeting society's needs, aspirations and expectations for a better life will require growing supplies of reliable, affordable and lower-carbon energy.

Multi-Energy Systems

We need to continue to keep all energy options open and to develop, as appropriate, all primary energy supplies. Keeping all energy options available will enable every nation to tailor its approach to addressing energy needs and climate change in the most efficient way, in alignment with their respective resource base and long-term strategic development objectives. One critical tool in the arsenal is energy efficiency, as it is a critical component of any comprehensive sustainable energy strategy and can make a significant and short-term impact on emissions of greenhouse gases. Energy efficiency needs to be promoted among producers and consumers of energy through the establishment of appropriate fiscal and regulatory frameworks. However more action is needed to turn ideas into action. Globally everyone needs to identify opportunities to reduce their consumption of energy and improve efficiency. Many countries and companies are doing exactly that – and some will be left behind if they do not also rise to the occasion.

At the same time it does not help to address only one element of the energy sector. Energy supply and use pose political and economic issues related to economic growth, security, employment, investment, climate change, environmental impacts and trade.

Consequently, energy challenges should be addressed through integrated policies reflecting a broad range of issues including development priorities and needs; social conditions and aspirations; trade rules; environmental policies; and the promotion of innovation, together with technology development and transfer policies and energy efficiency. Climate change is a multifaceted and broad-based issue and thus it is particularly important that climate change issues are integrated into all relevant policies.

The long road ahead

Let us not fail to fully understand the magnitude of the challenge facing us. The challenge that we face is bigger than one country or company and the evolution of energy systems will require considerable time and expense in order to alter energy and raw material inputs, operations and products and to develop and introduce technological innovations, as well as to establish the infrastructure to support them. Companies and governments should take these long-term considerations and realities into account, and strive for consistency and predictability over the corresponding time span.

Maintaining and growing the energy supplies required to provide access to those lacking it and to meet future demand with reduced environmental impacts will require significant investment in the long term in every element of the supply and use chain. This investment is estimated by the IEA to be US$ 20 trillion by 2030. Mobilising the required energy investments will be a key challenge. In countries with limited capital, and specifically for the least-developed countries, the role of Foreign Direct Investment should be complemented by Inter-Governmental Organisation funds, Official Development Assistance (ODA), and local private funds. Through such innovative financing solutions, project creation and implementation benefit from a variety of sources of funds, which are mutually reinforcing, each fund being adapted to the type of investment and risks it covers.

The challenge of climate change adds an additional dimension to this issue and historical paradigms of investment in infrastructure must be challenged if we are to meet the challenges of ridding the world of energy starvation through a cleaner and lower carbon-emitting path. In adopting a holistic approach to this value chain there is a significant opportunity for the public and private sector to work together to build lower carbon-emitting energy infrastructure and then use it for economic, social and environmental development.

Energy for sustainable development will depend on the more widespread use of existing efficient technologies as well as the development, commercialisation and deployment of innovative and lower-carbon technologies. To expand and take advantage of the full potential of energy options, all relevant stakeholders should allocate resources to research and development of new technologies all along the energy chain. The energy sector dedicates substantial resources to technology advancement and the development of innovation but we also need to be a partner in defining mechanisms to identify, develop, commercialise and transfer technologies on a global scale. In order to accelerate the development and deployment of technologies, large demonstration or pilot activities should be considered in order to develop capacity and to increase the rate of uptake of key technologies. While fossil fuels will continue to play an important role in energy supply in the decades to come, every effort must be made to diversify the energy mix. Urgent action is required to further diversify energy supply by developing advanced, cleaner, more efficient, affordable and cost-effective energy technologies such as renewables (including large-scale hydropower) and nuclear power. In addition, quantum leaps need to be made in the implementation of energy efficiency measures. Further, in areas were water is scarce, the application of technologies such as dry cooling, needs to be employed. The publication of the data in this report can provide the foundation for sustainable energy planning as we move forward

This transformation, as well as meeting the need for skills to build and operate plant is critical. Education is essential to supporting research and facilitating efficient deployment and operation of energy technologies. Furthermore, education is important for helping users to make informed energy choices.

Conclusion

We know that the energy sector is a major contributor to global greenhouse gas emissions and in order to meet the challenges of meeting the rising demand for energy whilst reducing greenhouse gas emissions and adapting to the impacts of a changing climate, global efforts will be required. This has been the subject of the recently released WEC report on Energy and Climate Change. The efforts in this area require concerted action which replicates successes around the world and through public-private partnerships which leverage resources and channel international effort. The energy sector will not only be a key implementer of global policy, but will also contribute through innovation and the development and deployment of new technologies. It is recognised that there is no technological "silver bullet" but that all technologies are important to assess, including renewables and clean-coal technologies. In addition, technologies that result in significant cuts in greenhouse gases, such as nuclear power, have a crucial role to play. Carbon markets also have an important role to play and should be encouraged and normalised as far as possible.

In conclusion, I am a firm believer in the words of an eighteenth century British MP Edmund Burke, who said "Nobody made a greater mistake than he who did nothing because he could only do a little". We all play a vital role in contributing towards global imperatives and we need to define novel ways in which to leverage resources in meeting the challenges we collectively face.

Valli Moosa
Chairman of Eskom Holdings Limited

Contents

1. Coal

COMMENTARY

Reserves

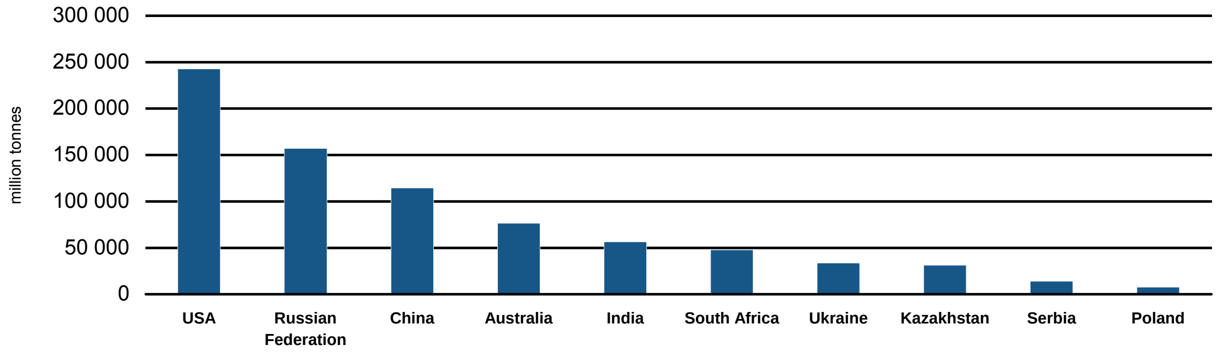
Amongst the major energy sources, coal is once again the most rapidly growing fuel on a global basis. While questions regarding the size and location of reserves of oil and gas abound, coal remains abundant – and broadly distributed around the world. Economically recoverable reserves of coal are available in more than 70 countries worldwide, and in each major world region. With authorities reporting some 850 billion tonnes of coal as currently recoverable (the geological resource is far larger), it is clear that coal will be with us for many decades, if not centuries, to come.

The fact that global coal reserves at end-2005 were, at 847.5 billion tonnes, some 61.5 billion tonnes or 6.8% lower than the corresponding total at end-2002 represents more of a refinement than a revision. After centuries of mineral exploration, the location, size and characteristics of most countries' coal resources are quite well known. What tends to vary much more than the assessed level of the resource (in other words, the potentially accessible coal in the ground) is the level classified as proved recoverable reserves (that is, the tonnage of coal that has been proved by drilling etc. and is economically and technically extractable).

The data on coal reserves and resources given in the present *Survey* (Tables 1-1, 1-2i, 1-2ii, 1-2iii) have been compiled from a variety of sources. The prime input has been provided by the Member Committees in WEC member countries. However,

Figure 1-1 Proved recoverable coal reserves: the top ten countries

Source: SER



on the one hand WEC membership does not include all countries with coal resources, and on the other, not all WEC members are able to respond to the questionnaire requesting data as input to the *Survey*. Consequently, other (mainly published) sources are consulted in order to complete the coverage of global resources. It should thus be noted that the resulting tabulations of reserves and resources are a compilation of existing data, not a set of specially-commissioned national assessments.

At the current rate of production, global coal reserves are estimated to last for almost another 150 years.

Compared with data appearing in the 2004 *Survey of Energy Resources*, North American reserves have decreased by 4 billion tonnes, all attributable to the gradual attrition of US reserves. South America shows a 3.5 billion tonnes reduction, mostly as a result of a 0.7 recovery factor being applied to Brazil, replacing the in-situ data previously reported. In Asia a significant change (down 41 billion tonnes) was largely due to improved data for India, where the WEC Member Committee was able to report reserves on a recoverable basis, rather than the in-situ data emanating from the Ministry of Coal. European reserves declined by 12 billion tonnes, over half of which was attributable to Poland, where reported reserves now refer to developed deposits only.

Energy Demand

There is no doubt that energy demand has grown astronomically in recent years – with primary energy demand increasing by more than 50% since 1980. This growth is forecast to continue – at an annual average rate of 1.6% between 2004 and 2030. Over 70% of this growth will come from developing countries, where populations and economies are growing considerably faster than in the OECD nations. China alone will account for some 30% of increased energy demand.

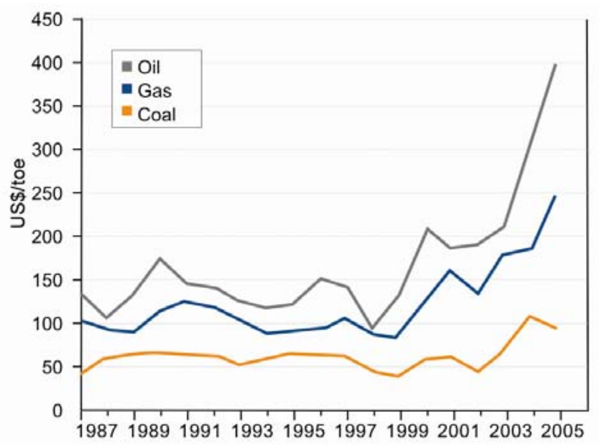
Fossil fuels will continue to provide more than 80% of the total energy demand well into the future, and – according to the International Energy Agency – coal will see the largest demand increase in absolute terms, from some 2 772 mtoe in 2004 to 4 441 mtoe in 2030. The greatest increase in the demand for coal will be in the developing countries, with 86% in developing Asia, where reserves are large and low-cost. India's coal use is expected to grow by some 3.3% per annum to 2030, more than doubling in absolute terms. OECD coal use is likely to grow modestly.

Energy Security

As this *Survey* shows, coal is plentiful, widely distributed and likely to be in continuing, and increasing, demand for the foreseeable future. Either the use of indigenous reserves or the ability to access a well-provided and affordable international market can enhance a country's or region's energy security, and provide affordable, reliable power to drive economies and development.

The key production centres for oil and gas – now that US and North Sea production are in decline – are considered geopolitically less stable, and an

Figure 1-2 Energy price trends (1987-2005)
Source: BP 2005



increasing reliance on imports can, for many countries, only be considered ‘energy-insecure’. Recent supply disruptions in oil and gas – whether from the weather or for political reasons – have exacerbated these pressures to provide secure and steady energy.

A further key factor is coal’s relative affordability and lack of price volatility. Coal has consistently outperformed oil and gas on an equivalent-energy basis, and despite a potential cost of carbon, coal is likely to remain the most affordable fuel for power generation in many developing and industrialised countries for several decades. Events in 2006 led to oil prices rising to around US$ 80/bbl and gas prices spiking to new highs, underlining coal’s key role in power generation worldwide.

Inter-fuel Substitution – Coal to Liquids

Of course, high oil and gas prices do not solely impact on power generation, but raise credible economic possibilities for inter-fuel substitution.

Oil provides 35% of global energy consumption and more oil is used today than ever before. Demand for oil will continue to grow, primarily owing to rapid growth in vehicle ownership in developing nations. Energy security concerns in the oil sector are increasing, owing to questions of resource availability, supply security, political instability and infrastructure difficulties. Oil prices are expected to remain high.

The development of a coal-to-liquids (CTL) industry can serve as a hedge against oil-related energy security risks, minimising exposure to oil price volatility and foreign currency risk, while providing the liquid fuels needed for economic growth. CTL can provide ultra-clean fuels for transport, domestic use and power generation, while the use of carbon capture and storage can minimise greenhouse gas emissions from the production process.

Production of liquid fuels from coal has been carried out in South Africa since the 1950s and is now undertaken on a commercial, non-subsidised basis.

Projects are under way and planned in several countries around the world – perhaps not surprisingly, countries which have large indigenous coal reserves but import substantial amounts of oil. The USA and China have projects in operation, while South Africa is reportedly considering an expansion of its production. Monash Energy is planning a new project in south-eastern Australia which will use the local brown coal as a feedstock. The CO_2 emissions will be piped for enhanced oil recovery in the Bass Strait. Serious interest has been shown in projects in Indonesia, India and Germany.

Clean Coal Technologies

An array of clean coal technologies has been, and continues to be, developed to address environmental concerns surrounding coal utilisation. Traditional pollution-control technologies

Figure 1-3 Power plant performance
Source: International Energy Agency

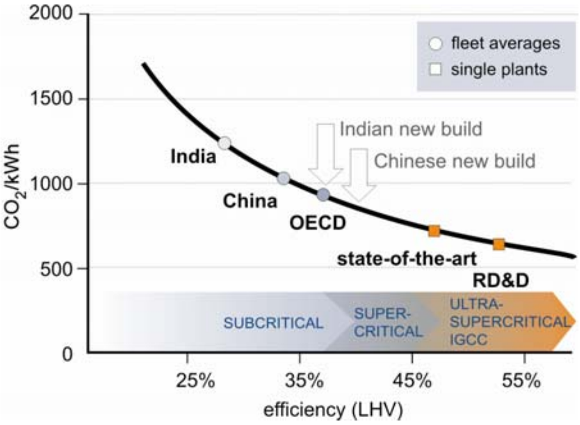
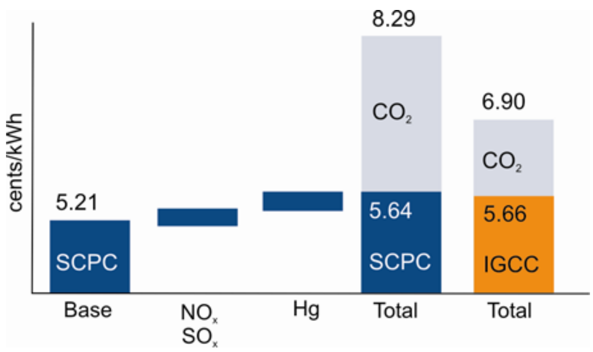


Figure 1-4 Cost of electricity comparison
Source: IGCC Alliance - GE



(SCPC - Supercritical Pulverised Coal)

have been installed worldwide to address sulphur, oxides of nitrogen and particulate-matter emissions, and retrofit programmes continue to improve power plant performance. However, more remains to be done, and greater deployment of these technologies must be encouraged.

As climate concerns have come to the fore, increasing the combustion efficiency of both conventional and advanced new power systems has become paramount. The development of innovative techniques such as carbon capture and storage will lead to a near-zero emissions future for coal.

New power plants worldwide are being built to perform at ‘supercritical’ and ‘ultrasupercritical’ conditions of temperature and pressure, increasing electricity generation efficiency to 40-50% and higher. China has engaged on an aggressive strategy of power generating capacity growth, with some 93 000 MW of coal-fired plant added in 2006. The first 1 000 MW supercritical plant came online in November 2006, in line with the Chinese Government’s aim of phasing out small, inefficient plant.

Integrated Gasification Combined Cycle (IGCC) is another advanced technology which holds out a number of benefits for coal-fired power generation. Coal is not burnt to raise steam, as with conventional power plants, but instead reacted to form a synthesis gas of hydrogen and carbon monoxide. A gas turbine is used to generate electricity, with waste heat being used to raise steam for a secondary steam turbine. Not only are efficiencies raised in doing so - thereby reducing emissions of CO_2 - but pollutant emissions are also significantly reduced, even compared to advanced conventional technologies, with 33% less NO_x, 75% less SO_x and almost no particulate emissions. IGCC uses 30-40% less water than a conventional plant and up to 90% of mercury emissions can be captured (at typically one-tenth of the costs for a conventional plant).

One of the main barriers to the widespread uptake of IGCC in the past has been cost. IGCCs have been significantly more expensive than conventional coal-fired plant – typical comparisons have suggested US$ 1 500/kW for IGCC compared with US$ 750/kW for conventional plants and US$ 1 000/kW for advanced conventional systems such as supercritical power plants. However, recent studies in the USA (IGCC Alliance) have shown that the cost of IGCC is similar to that of supercritical plant, on a cost-of-electricity (COE) basis, once the cost of SO_x, NO_x and mercury emission allowances are taken into account. Where a price for CO_2 must also be factored in, IGCC is significantly more competitive.

IGCC provides a more cost-effective route for capturing CO_2 – EPRI’s *CoalFleet for Tomorrow* programme has found that the incremental cost penalty for removal of CO_2 from IGCC syngas is considerably lower than that for its removal from the flue gas of a supercritical unit.

Carbon Capture and Storage

Addressing climate concerns means mitigating emissions of greenhouse gases. The power sector is one of the main contributors to worldwide CO_2

The Intergovernmental Panel on Climate Change (IPCC) has estimated that there is a worldwide storage capacity of at least 2 000 billion tonnes of CO_2.

emissions, and recognises that emissions will have to be addressed in a carbon-constrained future – but without impacting economic growth and energy security. A vital tool in stabilising atmospheric CO_2 concentrations is carbon capture and storage (CCS), whereby CO_2 is removed from flue gases – from power generation or other industrial activity – and injected underground; for example, into deep saline aquifers or used for enhanced oil recovery.

There are several different types of CO_2 capture systems: post-combustion, pre-combustion and oxyfuel combustion. The concentration of CO_2, the pressure in the gas flow and the fuel type (solid or gas) are important factors in selecting the appropriate capture system. Pipelines are preferred for transporting large amounts of CO_2 for distances up to around 1 000 km. For amounts smaller than a few million tonnes of CO_2 per year or for transportation over larger distances overseas, the use of ships, where applicable, to transport CO_2 is economically more attractive. Storage of CO_2 in deep onshore or offshore geological formations (oil and gas fields, saline formations, unmineable coal beds) uses many of the same technologies that have been developed by the oil and gas industry and has been proved to be economically feasible under specific conditions for oil and gas fields and saline formations, but not yet for storage in unmineable coal beds.

The Intergovernmental Panel on Climate Change (IPCC) has estimated that there is a worldwide storage capacity of at least 2 000 billion tonnes of CO_2, which is expected to account for up to 55% of the cumulative mitigation effort up to 2100. Importantly, the IPCC also notes that the costs of mitigation may be reduced by 30% or more when CCS is included in a climate-stabilisation strategy. Studies are under way globally to ascertain more detail regarding the location and capacity of suitable storage sites.

Carbon capture has been undertaken for many years in the oil and gas industry, and in the coal-processing sector: the Dakota Gasification plant in the USA gasifies coal to provide synthetic natural gas and exports the CO_2 to Canada, for use in enhanced oil recovery. However, experience is yet to be gained on CCS from a coal-fired power plant. A number of research and development projects worldwide are exploring the issues and opportunities, and demonstration plants are expected to be in operation from 2009 onwards (Fig. 1-6).

Coal Mine Methane

Coal mine methane (CMM) is a relatively large and undeveloped resource, but its utilisation is garnering increasing attention as a method for reducing greenhouse gas emissions.

China, Russia, Poland and the United States account for over 77% of coal mine methane emissions. Emissions are projected to grow 20% from 2000 to 2020, with China increasing its share of worldwide emissions from 40% to 45%. By 2020, it is estimated that methane emissions from coal mining activities will be 449 mt CO_{2e}

Currently only a fraction of the CMM resource is recovered in a suitable form to be used for heat or power production.

Figure 1-5 Carbon capture and storage demonstration projects

Source: WCI

	Location	Capacity (MW)	Expected Year of Start-up	Comments
ZeroGen	Australia	50	2010	ZeroGen involves IGCC power plant technology with CCS – storage will be in a saline aquifer.
Hydrogen Energy - BP & Rio Tinto	Australia	500	Investment decision could be made in 2011, with project in operation after three year construction period.	Located in Kwinana, the power station will be the first hydrogen-fuelled power project, enabling the capture and transportation of around 4 mt/CO_2 each year in a geological formation beneath the seabed of the Perth Basin.
SaskPower	Canada	300	2012	The SaskPower project will use lignite with post-combustion capture or oxy-fuel technology. The project will capture approximately 8 000 t CO_2/d which will be used for EOR in the region.
GreenGen	China	250	2018	GreenGen will commission a 250 MW IGCC plant by 2009, with scale-up in 2012 and full integration with CCS by 2018.
Dynamis - Hypogen	Europe	250	2012	The project is co-funded by the European Commission under the sixth Framework Programme (FP6) and consists of large-scale power generation using advanced power cycles with hydrogen-fuelled gas turbines. The project will investigate routes to large-scale cost-effective co-production schemes for hydrogen and electricity with full integrated CO_2 management.
RWE	Germany	400-450	2014	The first of the RWE proposals will use IGCC technology and will be able to separate hydrogen after gas treatment and cleaning to use directly as an energy source or in synthetic fuel production. CO_2 will be stored in a depleted gas reservoir or saline aquifer.
Vattenfall	Germany	250	2020	Vattenfall are due to finish their 30 MW CCS pilot plant in 2008. This pilot plant will provide a platform for the R&D required in order to build a larger commercial-scale plant (1 000 MW) by 2020.
Progressive Energy	UK	800	2011	The Progressive Energy project will use IGCC and capture 5 mt of CO_2/yr to be used for EOR in the central North Sea. The project will be able to operate on coal or petroleum coke, with the possibility of including biomass.
Powerfuel	UK	900	Post-2012	The Powerfuel IGCC CCS project is to be located at the Hatfield Colliery (South Yorkshire), closed in 2004 and due to reopen by end-2007. The colliery is owned and operated by Powerfuel.
E.ON	UK	450	Post-2012	This IGCC project will be co-located with E.ON's existing gas-fired power plant in Killingholme. The first phase of the project would be the construction of the power plant with CCS being added in a second phase.
E.ON	UK	2 x 800	2015	E.ON UK will build two new 800 MW supercritical units at its Kingsnorth power station, once the current 4 x 485 MW units have ceased operation by the end of 2015.
RWE nPower	UK	1 000	2016	The second of the RWE proposals will investigate supercritical technology combined with post-combustion CCS at Tilbury. This is the largest of all the proposed CCS projects to date.
Carson Project	USA	500	2011	Hydrogen Energy, along with partner Edison Mission Energy, intends to use a gasifier to convert petroleum coke to H_2 and CO_2, and then use the hydrogen as a fuel for a 500 MW power station and store up to 5 mt CO_2/yr deep underground.
FutureGen	USA	275	2012	FutureGen will use IGCC to produce electricity and hydrogen as well as CCS. The project is a partnership between the US DOE and industry.

Figure 1-6 Estimated available coal reserves and corresponding gas reserves from underground coal gasification

Source: UCG Partnership and SER

	Estimated available coal reserves for UCG (billion tonnes)	Potential gas reserves from UCG (as Natural Gas) (trillion m^3)	Current natural gas reserves (end-2005) (trillion m^3)
USA	138.1	41.4	5.9
Europe	130.1	21.8	5.7
Russian Federation	87.9	26.3	47.8
China	64.1	19.2	2.4
India	51.8	15.5	1.1
South Africa	48.7	8.2	N
Australia	44.0	13.2	0.8
Total	**564.7**	**145.6**	**63.7**

Worldwide, there are several power generation projects operating at coal mines. Power production from CMM has been developing for more than a decade in countries such as Australia, Germany, Japan, the UK and the USA. In the past two years there have been rapid developments in CMM utilisation for power production in a number of markets, most notably China, but also in Poland and Ukraine. According to 2005 data, there are roughly fifty projects operating worldwide at abandoned and active coal mines, ranging in size from 150 kW_e to 94 MW_e and totalling more than 300 MW_e.

An important driver for CMM in developing countries is the Clean Development Mechanism - there are currently five registered CMM projects and likely to be many more.

Underground Coal Gasification

Underground Coal Gasification (UCG) is another burgeoning area of interest. UCG allows access to more of the physical global coal resource than would be included in current economically recoverable reserve estimates. Where mining is no longer taking place, for economic or geological reasons, UCG permits exploitation of deposits by the controlled gasification (again a reaction of coal to form a syngas) of coal seams *in situ*. Carbon dioxide from the process can safely be returned to the gasified seam, resulting in zero emissions and very little ground disturbance.

Feasibility studies and demonstrations are ongoing in the UK, Russia, China, South Africa and New Zealand, amongst others.

Early studies suggest that the use of UCG could potentially increase world reserves by as much as 600 billion tonnes.

It is clear that coal has a future as part of a balanced energy mix, and that new technology and applications are being developed to utilise the world's largest fossil energy resource. What is also clear is that the world is at the beginning of a carbon-constrained future. A great deal has been done to alleviate local and regional pollution from coal applications, although greater utilisation of these technologies is vital. Carbon capture and storage is a key mitigation option in ensuring that the sustainability triptych of economic growth, energy security and environmental impacts is met.

Christine Copley
World Coal Institute

DEFINITIONS

Proved amount in place is the resource remaining in known deposits that has been carefully measured and assessed as exploitable under present and expected local economic conditions with existing available technology.

Maximum depth of deposits and minimum seam thickness relate to the proved amount in place.

Proved recoverable reserves are the tonnage *within* the proved amount in place that can be recovered in the future under present and expected local economic conditions with existing available technology.

Estimated additional amount in place is the indicated and inferred tonnage *additional to* the proved amount in place that is of foreseeable economic interest. It includes estimates of amounts which could exist in unexplored extensions of known deposits or in undiscovered deposits in known coal-bearing areas, as well as amounts inferred through knowledge of favourable geological conditions. Speculative amounts are not included.

Estimated additional reserves recoverable is the tonnage *within* the estimated additional amount in place that geological and engineering information indicates with reasonable certainty might be recovered in the future.

NOTE:

The quantifications of reserves and resources presented in the tables that follow incorporate, as far as possible, data reported by WEC Member Committees. Such data will reflect the respective Member Committees' interpretation of the above Definitions in the context of the reserves/resources information available to them, and the degree to which particular countries' terminology and statistical conventions are compatible with the WEC specifications.

TABLES

Table Notes

The tables cover bituminous coal (including anthracite), sub-bituminous coal and lignite. Data for peat are given in Chapter 8. There is no universally accepted system of demarcation between coals of different rank and, in particular, what is regarded as sub-bituminous coal tends to vary from one country to another. Moreover, if it is not isolated as such, sub-bituminous is sometimes included with bituminous and sometimes with lignite.

Table 1-1 Coal: proved recoverable reserves at end-2005 (million tonnes)

	Bituminous including anthracite	Sub-bituminous	Lignite	TOTAL
Algeria	59			59
Botswana	40			40
Central African Republic			3	3
Congo (Democratic Rep.)	88			88
Egypt (Arab Rep.)	21			21
Malawi		2		2
Morocco	N			N
Mozambique	212			212
Niger	70			70
Nigeria	21	169		190
South Africa	48 000			48 000
Swaziland	208			208
Tanzania	200			200
Zambia	10			10
Zimbabwe	502			502
Total Africa	**49 431**	**171**	**3**	**49 605**
Canada	3 471	871	2 236	6 578
Greenland		183		183
Mexico	860	300	51	1 211
United States of America	112 261	100 086	30 374	242 721
Total North America	**116 592**	**101 440**	**32 661**	**250 693**
Argentina		424		424
Bolivia	1			1
Brazil		7 068		7 068
Chile	31	1 150		1 181
Colombia	6 578	381		6 959
Ecuador			24	24
Peru	140			140
Venezuela	479			479
Total South America	**7 229**	**9 023**	**24**	**16 276**
Afghanistan	66			66
China	62 200	33 700	18 600	114 500

Table 1-1 Coal: proved recoverable reserves at end-2005 (million tonnes)

	Bituminous including anthracite	Sub-bituminous	Lignite	TOTAL
India	52 240		4 258	56 498
Indonesia	1 721	1 809	798	4 328
Japan	355			355
Kazakhstan	28 170		3 130	31 300
Korea (Democratic People's Rep.)	300	300		600
Korea (Republic)		135		135
Kyrgyzstan			812	812
Malaysia	4			4
Mongolia				
Myanmar (Burma)	2			2
Nepal		1		1
Pakistan	1	167	1 814	1 982
Philippines	41	170	105	316
Taiwan, China	1			1
Thailand			1 354	1 354
Turkey			1 814	1 814
Uzbekistan	1 000		2 000	3 000
Vietnam	150			150
Total Asia	**146 251**	**36 282**	**34 685**	**217 218**
Albania			794	794
Bulgaria	5	63	1 928	1 996
Czech Republic	1 673	2 617	211	4 501
Germany	152		6 556	6 708
Greece			3 900	3 900
Hungary	199	170	2 933	3 302
Ireland	14			14
Italy		10		10
Montenegro				
Norway		5		5
Poland	6 012		1 490	7 502
Portugal	3		33	36
Romania	12	2	408	422
Russian Federation	49 088	97 472	10 450	157 010

Table 1-1 Coal: proved recoverable reserves at end-2005 (million tonnes)

	Bituminous including anthracite	Sub-bituminous	Lignite	TOTAL
Serbia	6	379	13 500	13 885
Slovakia	2		260	262
Slovenia		21	211	232
Spain	200	300	30	530
Ukraine	15 351	16 577	1 945	33 873
United Kingdom	155			155
Total Europe	**72 872**	**117 616**	**44 649**	**235 137**
Iran (Islamic Rep.)	1 386			1 386
Total Middle East	**1 386**			**1 386**
Australia	37 100	2 100	37 400	76 600
New Caledonia	2			2
New Zealand	33	205	333	571
Total Oceania	**37 135**	**2 305**	**37 733**	**77 173**
TOTAL WORLD	**430 896**	**266 837**	**149 755**	**847 488**

Notes:

1. Quantifications of proved recoverable reserves for Mongolia and Montenegro are not available
2. Sources: WEC Member Committees, 2006/7; data reported for previous WEC Surveys of Energy Resources; national and international published sources

Table 1-2i Bituminous coal (including anthracite): resources at end-2005

	Proved amount in place			Estimated additional	
	Tonnage (million tonnes)	Maximum depth of deposits (metres)	Minimum seam thickness (metres)	Amount in place (million tonnes)	Reserves recoverable (million tonnes)
Africa					
Algeria	64	400	0.1	164	35
South Africa	115 000	350	1.0		
North America					
Mexico					426
United States of America	244 313	671	0.25	445 346	
South America					
Argentina	4				
Asia					
India	95 866	1 200	1.0	157 435	97 076
Indonesia	3 448			6 035	57
Japan	4 768	900	0.6	6 298	
Pakistan	1	1 200	0.3	5	3
Philippines	50				108
Taiwan, China	100	800	0.4		
Europe					
Austria	1				
Bulgaria	428	150	0.6		
Croatia	4				
Czech Republic	5 880	1 600	0.6		8 541
Germany	319	1 500	0.6	8 065	
Hungary	1 597	1 000	0.4	298	37
Poland	15 291	1 000	1.0	27 405	
Romania	22	950	2.0	2 143	174
Russian Federation [3]	194 000			> 200 000	
Serbia	27		0.5		
Slovakia	2				6
Spain	812	> 1 200			
Ukraine	20 467	1 800	0.55	5 170	3 877

Table 1-2i Bituminous coal (including anthracite): resources at end-2005

	Proved amount in place			Estimated additional	
	Tonnage (million tonnes)	Maximum depth of deposits (metres)	Minimum seam thickness (metres)	Amount in place (million tonnes)	Reserves recoverable (million tonnes)
Middle East					
Iran (Islamic Rep.)	11 143				
Oceania					
New Zealand	45			942	313

Notes:

1. The data on resources are those reported by WEC Member Committees. They thus constitute a sample, reflecting the information available in particular countries: they should not be considered as complete, or necessarily representative of the situation in each region. For this reason, regional and global aggregates have not been computed
2. Sources: WEC Member Committees, 2006/7
3. Russian Federation: the figures represent 'Discovered Reserves' and 'Balance Reserves', respectively, and include all ranks of coal

Table 1-2ii Sub-bituminous coal: resources at end-2005

	Proved amount in place			Estimated additional	
	Tonnage (million tonnes)	Maximum depth of deposits (metres)	Minimum seam thickness (metres)	Amount in place (million tonnes)	Reserves recoverable (million tonnes)
North America					
Mexico					148
United States of America	163 587	305	1.52	273 593	
South America					
Argentina	697	800	0.5/2.0	273	
Brazil	17 017	870	0.5	15 319	7 660
Asia					
Indonesia	4 997			27 601	476
Japan				5 936	
Korea (Republic)	222	1 000	0.6	812	201
Nepal	1	74	0.5	7	
Pakistan	279	1 200	0.2	4 704	2 822
Philippines	242				79
Turkey	42			37	29
Europe					
Bulgaria	278	390	1.5		
Czech Republic	2 305	500	2.0		4 501
Hungary	3 203	500	0.8	1 289	78
Italy	10	530	2.0	600	100
Romania	8	250	1.4	230	13
Russian Federation [3]					
Serbia	571		2.0		
Slovenia	82	190	10.0	27	27
Spain	346	1 200			
Ukraine	22 103	1 800	0.6	5 875	4 407
Oceania					
New Zealand	376			2 085	682

Notes:

1. The data on resources are those reported by WEC Member Committees. They thus constitute a sample, reflecting the information available in particular countries: they should not be considered as complete, or necessarily representative of the situation in each region. For this reason, regional and global aggregates have not been computed
2. Sources: WEC Member Committees, 2006/7
3. Russian Federation: see Table 1-2i

Table 1-2iii Lignite: resources at end-2005

	Proved amount in place			Estimated additional	
	Tonnage (million tonnes)	Maximum depth of deposits (metres)	Minimum seam thickness (metres)	Amount in place (million tonnes)	Reserves recoverable (million tonnes)
North America					
Mexico					26
United States of America	39 283	61	0.76	393 822	
South America					
Argentina	7 350	680			
Asia					
India	4 258			32 893	
Indonesia	4 021			11 103	
Japan				1 186	
Pakistan	3 024	150	0.3	63 364	38 018
Philippines	152				71
Thailand	2 056			2 857	
Turkey	2 124	700	0.7	259	230
Europe					
Austria	333				
Bulgaria	3 710	100-120	0.8		
Croatia	41				
Czech Republic	623	130	1.5		175
Germany	7 136	500	3.0	34 100	
Hungary	5 803	20	1.0	1 341	
Poland	1 878	350	3.0	11 837	
Romania	3 876	160	1.0/3.0	7 947	1 394
Russian Federation [3]					
Serbia	20 578		10.0		
Slovakia	519	600	2.5		575
Slovenia	562	547	8.0	13	13
Spain	238				
Ukraine	2 594	400	2.7	299	224
Oceania					
New Zealand	2 297			9 817	7 078

Notes:

1. The data on resources are those reported by WEC Member Committees. They thus constitute a sample reflecting the information available in particular countries: they should not be considered as complete or necessarily representative of the situation in each region. For this reason regional and global aggregates have not been computed
2. Sources: WEC Member Committees 2006/7
3. Russian Federation: see Table 1-2i

Table 1-3 Coal: 2005 production (thousand tonnes)

	Bituminous	Sub-bituminous	Lignite	Total
Algeria				
Botswana	985			985
Congo (Democratic Rep.)	110			110
Egypt (Arab Rep.)	35			35
Malawi		45		45
Morocco				
Mozambique	3			3
Niger	200			200
Nigeria		10		10
South Africa	244 986			244 986
Swaziland	222			222
Tanzania	31			31
Zambia	150			150
Zimbabwe	2 890			2 890
Total Africa	**249 612**	**55**		**249 667**
Canada	30 483	26 000	11 017	67 500
Mexico	4 800	7 000		11 800
United States of America	531 821	430 618	76 151	1 038 590
Total North America	**567 104**	**463 618**	**87 168**	**1 117 890**
Argentina	30			30
Brazil		6 260		6 260
Chile	140	590		730
Colombia	59 060			59 060
Peru	29			29
Venezuela	9 300			9 300
Total South America	**68 559**	**6 850**		**75 409**
Afghanistan	2			2
Bangladesh	87			87
Bhutan	85			85
China	2 120 000		70 000	2 190 000
Georgia	10			10
India	397 680		30 750	428 430
Indonesia	152 205			152 205
Japan	1 110			1 110
Kazakhstan	82 120		4 500	86 620
Korea (Democratic People's Rep.)	23 250	7 500		30 750
Korea (Republic)		2 800		2 800
Kyrgyzstan	50		290	340
Laos	250			250
Malaysia		790		790

Table 1-3 Coal: 2005 production (thousand tonnes)

	Bituminous	Sub-bituminous	Lignite	Total
Mongolia	1 650		6 130	7 780
Myanmar (Burma)			230	230
Nepal		12		12
Pakistan		2 590	2 000	4 590
Philippines		3 100		3 100
Taiwan, China				
Tajikistan	40	20		60
Thailand			21 420	21 420
Turkey	3 520		60 870	64 390
Uzbekistan	70		3 100	3 170
Vietnam	32 300			32 300
Total Asia	**2 814 429**	**16 812**	**199 290**	**3 030 531**
Albania			20	20
Austria	8		6	14
Bosnia-Herzogovina			9 000	9 000
Bulgaria	20	2 600	22 200	24 820
Croatia				
Czech Republic	13 254	48 305	467	62 026
FYR Macedonia			7 000	7 000
France		620		620
Germany	24 900		177 900	202 800
Greece		570	70 040	70 610
Hungary			9 570	9 570
Italy		60		60
Montenegro			1 290	1 290
Norway		1 470		1 470
Poland	97 900		61 600	159 500
Romania	2 995	138	31 122	34 255
Russian Federation	224 200		75 100	299 300
Serbia	65	363	34 565	34 993
Slovakia			2 510	2 510
Slovenia		594	3 945	4 539
Spain	8 500	3 300	7 600	19 400
Ukraine	78 037		360	78 397
United Kingdom	20 498			20 498
Total Europe	**470 377**	**58 020**	**514 295**	**1 042 692**
Iran (Islamic Rep.)	1 200			1 200
Total Middle East	**1 200**			**1 200**
Australia	271 410	36 500	70 920	378 830
New Zealand	2 543	2 477	246	5 266

Table 1-3 Coal: 2005 production (thousand tonnes)

	Bituminous	Sub-bituminous	Lignite	Total
Total Oceania	**273 953**	**38 977**	**71 166**	**384 096**
TOTAL WORLD	**4 445 234**	**584 332**	**871 919**	**5 901 485**

Notes:

1. Sources: WEC Member Committees, 2006/7; *BP Statistical Review of World Energy*, 2006; *World Mineral Production*, 2001-2005, British Geological Survey; national sources; estimates by the Editors

Table 1-4 Coal: 2005 consumption (thousand tonnes)

	Bituminous	Sub-bituminous	Lignite	Total
Algeria	800			800
Botswana	950			950
Congo (Democratic Rep.)	160			160
Egypt (Arab Rep.)	1 900			1 900
Ghana				
Kenya	128			128
Libya /GSPLAJ				
Madagascar	10			10
Malawi	60			60
Mauritania	7			7
Mauritius	300			300
Morocco	6 000			6 000
Mozambique	25			25
Namibia	4			4
Niger	178			178
Nigeria		10		10
South Africa	173 389			173 389
Swaziland	222			222
Tanzania	31			31
Tunisia				
Zambia	160			160
Zimbabwe	2 700			2 700
Total Africa	**187 024**	**10**		**187 034**
Canada	16 800	32 000	11 000	59 800
Cuba	15			15
Dominican Republic	750			750
Guatemala	500			500

Table 1-4 Coal: 2005 consumption (thousand tonnes)

	Bituminous	Sub-bituminous	Lignite	Total
Honduras	180			180
Jamaica	100			100
Mexico	2 700	14 100		16 800
Panama				
Puerto Rico				
United States of America	504 348	440 495	76 172	1 021 015
US Virgin Islands				
Total North America	**525 393**	**486 595**	**87 172**	**1 099 160**
Argentina	1 000			1 000
Brazil		21 600		21 600
Chile	5 200			5 200
Colombia	4 000			4 000
Peru	1 150			1 150
Uruguay	1			1
Venezuela	140			140
Total South America	**11 491**	**21 600**		**33 091**
Afghanistan	2			2
Armenia				
Azerbaijan	7			7
Bangladesh	700			700
Bhutan	70			70
China	2 075 000		70 000	2 145 000
Cyprus	60			60
Georgia	12			12
Hong Kong, China	10 825			10 825
India	418 900		30 750	449 650
Indonesia	41 306			41 306
Japan	181 900			181 900
Kazakhstan	58 000		4 000	62 000
Korea (Democratic People's Rep.)	23 000	7 500		30 500
Korea (Republic)	82 000	2 800		84 800
Kyrgyzstan	750		350	1 100
Malaysia	11 750	750		12 500
Mongolia	1 650		4 050	5 700
Myanmar (Burma)	120		70	190
Nepal		583		583
Pakistan	3 400	2 500	2 000	7 900
Philippines	6 940	3 100		10 040
Sri Lanka	95			95
Taiwan, China	59 363			59 363
Tajikistan	140	20		160

Table 1-4 Coal: 2005 consumption (thousand tonnes)

	Bituminous	Sub-bituminous	Lignite	Total
Thailand	8 580		21 000	29 580
Turkey	18 800		57 900	76 700
Uzbekistan	70		3 100	3 170
Vietnam	14 300			14 300
Total Asia	3 017 740	17 253	193 220	3 228 213
Albania			140	140
Austria	4 040		1 270	5 310
Belarus	220			220
Belgium	8 535	175	190	8 900
Bosnia-Herzogovina		3 400	5 800	9 200
Bulgaria	4 266	2 707	23 585	30 558
Croatia	1 080		80	1 160
Czech Republic	9 520	47 153	467	57 140
Denmark	6 233	N	N	6 233
Estonia	56			56
Finland	5 060			5 060
FYR Macedonia	10	40	7 000	7 050
France	20 590	760	40	21 390
Germany	68 200		178 000	246 200
Greece	570		70 040	70 610
Hungary	1 350	3 000	7 250	11 600
Iceland	117			117
Ireland	2 924			2 924
Italy	26 800			26 800
Latvia	100			100
Lithuania	285		3	288
Luxembourg	110			110
Moldova	109			109
Netherlands	12 000			12 000
Norway		720		720
Poland	81 900		61 600	143 500
Portugal	5 500			5 500
Romania	7 027	138	31 122	38 287
Russian Federation	132 100		66 000	198 100
Serbia	600	900	41 265	42 765
Slovakia	5 560		3 380	8 940
Slovenia	561	566	4 014	5 141
Spain	33 300	3 400	7 400	44 100
Sweden	3 200			3 200
Switzerland	100			100
Ukraine	58 424		304	58 728
United Kingdom	61 849			61 849

Table 1-4 Coal: 2005 consumption (thousand tonnes)

	Bituminous	Sub-bituminous	Lignite	Total
Total Europe	**562 296**	**62 959**	**508 950**	**1 134 205**
Iran (Islamic Rep.)	1 550			1 550
Israel	12 600			12 600
Lebanon	200			200
Total Middle East	**14 350**			**14 350**
Australia	40 000	36 500	71 000	147 500
Fiji	12			12
New Caledonia	260			260
New Zealand	2 540	3 677	276	6 493
Papua New Guinea	1			1
Total Oceania	**42 813**	**40 177**	**71 276**	**154 266**
TOTAL WORLD	**4 361 107**	**628 594**	**860 618**	**5 850 319**

Notes:

1. Sources: WEC Member Committees, 2006/7; *BP Statistical Review of World Energy*, 2006; national sources; estimates by the Editors

COUNTRY NOTES

The following Country Notes on Coal have been compiled by the Editors, drawing upon a wide variety of material, including information received from WEC Member Committees, national and international publications.

Major international published sources consulted included:

- *Energy Balances of OECD Countries 2003-2004*; 2006; International Energy Agency;
- *Energy Balances of Non-OECD Countries 2003-2004*; 2006; International Energy Agency;
- *Energy Statistics of OECD Countries 2003-2004*; 2006; International Energy Agency;
- *Energy Statistics of Non-OECD Countries 2003-2004*; 2006; International Energy Agency;
- *Quarterly Statistics, Fourth Quarter 2006*; 2007; International Energy Agency;
- *Major coalfields of the world*; June 2000; IEA Coal Research.

Argentina

Proved amount in place (total coal, million tonnes)	8 051
Proved recoverable reserves (total coal, million tonnes)	424
Production (total coal, million tonnes, 2005)	0.03

The principal coal-mining areas are located in the west of the country along the foothills of the Andes and in the Andes themselves, in the provinces of Catamarca, La Rioja, San Juan, Mendoza, Neuquén, Río Negro, Chubut and Santa Cruz, with smaller coalfields in Córdoba, the centre of Chubut and the Atlantic coast of Santa Cruz.

The biggest coalfield is Río Turbio, located to the west of the city of Río Gallegos in the southern province of Santa Cruz, close to the border with Chile. Río Turbio's coal is a steam coal with low sulphur content (down to 1%), falling into the sub-bituminous rank; it constitutes 99% of the hard coal resources of the country, and supports the only coal extraction activity in the Argentine Republic. The Río Turbio coalfield, including the concession for operating the associated railway and port facilities, was privatised in 1994 but is currently under administration by a Federal auditor.

The Argentinian WEC Member Committee has reported proved amounts in place of 697 million tonnes of sub-bituminous coal and 7 350 million tonnes of lignite, together with a minor quantity (4 million tonnes) of bituminous grade. For sub-bituminous, the maximum deposit depth is 800 m, with seams ranging from 0.5 to 2.0 m in minimum thickness. The lignite resources are at a maximum depth of 680 m. The only proved recoverable reserves reported are 424 million tonnes of sub-bituminous.

Coal output from the Río Turbio mine is now very modest, at around 30 thousand tonnes per annum, and is used for electricity generation.

Australia

Proved amount in place (total coal, million tonnes)	97 300
Proved recoverable reserves (total coal, million tonnes)	76 600
Production (total coal, million tonnes, 2005)	378.8

Australia is endowed with very substantial coal resources, with its proved recoverable reserves ranking 4th in the world. The major deposits of black coal (bituminous and sub-bituminous) are located in New South Wales and Queensland, especially in the Sydney and Bowen basins; smaller but locally important resources occur in Western Australia, South Australia and Tasmania. The main deposits of brown coal are in Victoria, the only State producing this rank. Other brown coal resources are present in Western Australia, South Australia and Tasmania.

The coal resource data included in the present *Survey* have been derived from *Australia's Identified Mineral Resources 2006*, published by Geoscience Australia. The proved amount of coal in place (reflecting 'Economic Demonstrated Reserves (EDR)') comprises 55.8 billion tonnes of black coal, (including an estimated 3.3 billion tonnes of sub-bituminous) and 41.5 billion tonnes of brown coal/lignite. Within these tonnages, the proportion deemed to be recoverable ranges from 39.2 billion tonnes (70%) of the bituminous coal to 90%, 37.4 billion tonnes of the lignite. A little over half of the recoverable bituminous, and all of the recoverable lignite, are surface-mineable. About 36% of Australia's massive reserves of bituminous coal are of coking quality. The maximum depth of the deposits ranges from 600 m in the case of bituminous coal to 200 m for sub-bituminous and 300 m for lignite. Minimum seam thicknesses are 0.3, 1.5 and 3.0 m, respectively.

'Subeconomic demonstrated resources' and 'inferred resources', additional to the proved amount in place, are vast: Geoscience Australia's current assessment puts those of black coal at 108 billion tonnes, of which 68 billion tonnes is estimated to be recoverable. Comparable figures for brown coal are 174 billion tonnes and 156 billion tonnes, respectively.

For a variety of reasons (e.g. environmental restrictions, government policies, military lands), not all of the tonnages classified as EDR are currently accessible: black coal reserves are only slightly affected, but the 'Accessible EDR' of brown coal are put at 30 billion tonnes, significantly lower than the quoted level of EDR, although still massive in tonnage terms.

In 2005 Australia produced 308 million tonnes of saleable black coal (bituminous and sub-bituminous) and 71 million tonnes of brown coal. The major domestic market for black coal is electricity generation: in 2004, power stations accounted for 85% of total black coal consumption, with the other major consumer being the iron and steel industry. Brown coal is used almost entirely for power generation.

Australia has been the world's largest exporter of hard coal since 1984: in 2005, it exported 233 million tonnes. About 54% of 2005 exports were of metallurgical grade (coking coal), destined largely for Japan, the Republic of Korea, India and Europe.

Botswana

Proved recoverable reserves (total coal, million tonnes)	40
Production (total coal, million tonnes, 2005)	1.0

Vast deposits of bituminous coal have been located in Botswana, principally in the eastern part of the country. The only mine to have been developed so far is at Morupule, near the town of Palapye, where Morupule Colliery Limited (controlled by Anglo American Corporation) commenced coal extraction in 1973.

For the present *Survey*, the resource data reported for the 2004 edition by the Botswana WEC Member Committee have been retained. Proved recoverable reserves were given as 40 million tonnes, of which 50% could be mined by open-cast methods. The reported tonnages related solely to the economically recoverable reserves that were being exploited at the Morupule Mine. With cumulative output to the end of 2005 amounting to some 20 million tonnes, Botswana's remaining proved amount of coal in place was reported to be 3 340 million tonnes.

All of Botswana's current coal production (985 thousand tonnes in 2005) is of power generation quality, none of coking quality. The Morupule mine's chief customers are the Botswana Power Corporation, the copper/nickel mine at Selibe-Phikwe and the soda ash plant at Sua Pan. The BPC power station at Morupule (net capacity 118 MW) generates about half of Botswana's electricity supplies, the balance being provided by imports from South Africa.

Brazil

Proved amount in place (total coal, million tonnes)	17 017
Proved recoverable reserves (total coal, million tonnes)	7 068
Production (total coal, million tonnes, 2005)	6.3

Brazil has considerable reserves of subbituminous coal, mostly located in the southern states of Rio Grande do Sul, Santa Catarina and Paraná.

For the present *Survey*, the Brazilian WEC Member Committee has reported a virtually unchanged level for the proved amount in place, at just over 17 billion tonnes, of which almost 42% is categorised as proved recoverable reserves. The maximum depth of the deposits is 870 m, whilst the minimum seam thickness is 0.5 m. There is estimated to be some 15.3 billion tonnes of additional coal in place, of which 50% is considered to be recoverable.

With respect to the stated level of proved recoverable reserves, it is estimated that 21% could be exploited through surface mining, and that 7% is considered to be of coking quality. In 2005, 65% of Brazilian coal production was obtained by surface mining.

Almost all of Brazil's current coal output is classified as steam coal, of which more than 85% is used as power-station fuel and the remainder in industrial plants. Virtually all of Brazil's metallurgical coal is imported: about 70% is used as input for coke production

Canada

Proved amount in place (total coal, million tonnes)	8 723
Proved recoverable reserves (total coal, million tonnes)	6 578
Production (total coal, million tonnes, 2005)	67.5

Canada has considerable coal resources, with proved reserves, according to the Geological Survey of Canada (GSC), of about 6.6 billion tonnes. Bituminous coals (including anthracite) are evaluated as 3.5 billion tonnes, sub-bituminous grades are put at approximately 0.9 billion tonnes; and lignite at 2.2 billion tonnes.

Estimates of the tonnages of coal that are considered to be additional to the ‘proved’ amounts of each rank total almost 190 billion tonnes. While these figures are approximate, they do serve to underline Canada’s large coal endowment.

Canadian coal reserves are mainly located in the western provinces of Saskatchewan, Alberta and British Columbia, with smaller deposits in the eastern provinces of Nova Scotia and New Brunswick. Bituminous deposits are found in the two eastern provinces together with Alberta and British Columbia; Alberta also possesses sub-bituminous grades, while lignite deposits are found only in Saskatchewan.

Western Canada dominates coal production, accounting for over 95% of the total. Alberta is the largest coal-producing province, mainly of thermal grades. British Columbia is the second largest, producing mainly metallurgical coals. Saskatchewan produces lignite. About 40% of Canadian coal production, principally metallurgical, is exported.

Around 90% of Canadian coal consumption is used for electricity generation, 7% in the steel industry and 3% in other industries. Alberta is the largest coal-consuming province, Ontario the second. Ontario and Nova Scotia rely on coal imports.

The Canadian coal industry is privately owned. Output is mainly from surface mines: there are two operating underground mines, Campbell River, British Columbia and Grande Cache, Alberta. Production from these operations is relatively small, about 1 million tonnes of coal annually. The potential exists to reopen the underground mine at the Donkin coal resource in Nova Scotia.

China

Proved recoverable reserves (total coal, million tonnes)	114 500
Production (total coal, million tonnes, 2005)	2 190.0

China is a major force in world coal, standing in the front rank in terms of reserves, production and consumption. The levels of proved recoverable reserves (as at end-1990), originally provided by the Chinese WEC Member Committee for the 1992 *Survey*, have been retained for each successive edition; in billions of tonnes, they amount to: bituminous coal and anthracite 62.2; sub-bituminous coal 33.7 and lignite 18.6. The level of proved reserves retained for the present *Survey* implies a coal R/P ratio of 52, on the basis of 2005 production.

It is interesting to note that the same figure (114.5 billion tonnes) for total proved reserves was quoted at the 11th Session of the UN Committee on Sustainable Energy (Geneva, November 2001), in the context of an estimate of 988 billion tonnes for China's coal resources. This reference, in a paper co-authored by Professor Huang Shengchu, a vice-president of the China Coal Information Institute, indicates a degree of continuity in the official assessments of China's coal reserves and supports the retention of the level originally advised by the Chinese WEC Member Committee in 1991.

Information received in mid-2007 in a private communication from an expert Chinese source confirms a level of approximately 1 000 billion tonnes for China’s ‘demonstrated’ or ‘explored’ reserves, including all grades from proved to prospective, on an in-situ basis.

Coal deposits have been located in most of China's regions but three-quarters of proved recoverable reserves are in the north and northwest, particularly in the provinces of Shanxi, Shaanxi and Inner Mongolia.

After more than 20 years of almost uninterrupted growth, China's coal production peaked at nearly 1.4 billion tonnes in 1996, followed by 4 years during which output was constrained by the closure of many small local mining operations. Annual output has followed a steep upward path since 2002 and reached a new peak in 2005. By far the greater part of output is of bituminous coal: lignite constitutes only about 3%.

The major coal-consuming sectors are power stations (including CHP), which accounted for 56% of total consumption in 2004, the iron and steel industry with a 17% share, and other industrial users with about 21%.

Coal exports have fallen back sharply in recent years, dropping from 95 million tonnes in 2003 to 87 million in 2004 and 72 in 2005: data for the first three quarters of 2006 indicate a continued decline.

Colombia

Proved recoverable reserves (total coal, million tonnes)	6 959
Production (total coal, million tonnes, 2005)	59.1

Colombia's vast coal resources are located in the north and west of the country. Data on 'measured reserves', published in 2004 by the Instituto Colombiano de Geología y Minería, Ministerio de Minas y Energía, indicate a total of 7 064 million tonnes, of which the Cerrejón Norte, Central and Sur fields in the department of La Guajira accounted for 56% and fields in the department of Cesar for 29%. For the present *Survey*, proved recoverable reserves have been based on this level, adjusted for cumulative coal production in 2004 and 2005. 'Indicated reserves' quoted in the same publication are 4 572 million tonnes, whilst 'inferred' tonnages are 4 237 million and 'hypothetical' resources 1 120 million.

Virtually all Colombia's coal resources fall into the bituminous category: the reserves in the Alto San Jorge field in Córdoba, with an average calorific value in the sub-bituminous/lignite bracket, are shown under sub-bituminous in Table 1-1.

Development of Colombian coal for export has centred on the Cerrejón deposits which are located in the Guajira Peninsula in the far north, about 100 km inland from the Caribbean coast. The coal is found in the northern portion of a basin formed by the Cesar and Rancheria rivers; the deposit has been divided by the Government into the North, Central and South Zones. In October 1975 the Government opened international bidding for the development of El Cerrejón-North Zone reserves and in December 1976 Carbocol (then 100% owned by the Colombian State) and Intercor (an Exxon affiliate) entered into an Association Contract for the development and mining of the North Zone. The contract has three phases and covers a 33-year period with the production phase scheduled to end early in 2009.

Carbocol was privatised in October 2000, the purchasers being a consortium of Anglo-American, Billiton and Glencore; in early 2002 the three partners acquired the whole of Intercor's interest.

Coal exports from Colombia totalled 55 million tonnes in 2005, equivalent to over 90% of its coal production. Cerrejón North remains one of the world's largest export mines.

Czech Republic

Proved amount in place (total coal, million tonnes)	8 808
Proved recoverable reserves (total coal, million tonnes)	4 501
Production (total coal, million tonnes, 2005)	62.0

The Czech Republic possesses sizeable coal resources, with a proved amount in place of nearly 9 billion tonnes, of which just over half is reported to be economically recoverable. In terms of rank, 37% of the proved reserves are classified as bituminous, 58% as sub-bituminous and 5% as lignite. The tonnages reported by the Czech WEC Member Committee for the present *Survey* show fairly considerable changes from those advised for the 2004 *Survey* in 2003: a 19-20% decline in proved reserves of both bituminous and sub-bituminous, and an overall 9% fall in the proved amount of coal in place, with bituminous dropping 18% and sub-bituminous increasing by 19%. The maximum depth of deposits varies from 1 600 m in the case of bituminous to 500 m for sub-bituminous and only 130 m for lignite; minimum seam thicknesses range from 0.6 (for bituminous) to 1.5 (lignite) and 2.0 m for sub-bituminous.

Bituminous coal deposits are mainly in the Ostrava-Karviná basin in the east of the country, and lie within the Czech section of the Upper Silesian coalfield. The principal sub-bituminous/lignite basins are located in the regions of North and West Bohemia, close to the Krusne Hory (Erzgebirge or Ore Mountains), which constitute the republic's north-western border with Germany. Currently all Czech output of bituminous coal and lignite is deep-mined.

Since 1990, Czech output of bituminous coal has fallen by 41%, to 13.3 million tonnes in 2005, whilst sub-bituminous/lignite has declined by 39%, from 80 million tonnes in 1990 to 48.8 million tonnes in 2005. Over half of the republic's bituminous coal production consists of coking coal. In 2004, total exports of coal amounted to 6.7 million tonnes, equivalent to nearly 11% of production.

Apart from its coking coal, which is consumed by the iron and steel industry, most of the republic's bituminous coal is used for electricity and heat generation, with industrial and private consumers accounting for relatively modest proportions. This pattern of utilisation also applies to sub-bituminous coal, which is still the main power station fuel.

Germany

Proved amount in place (total coal, million tonnes)	7 455
Proved recoverable reserves (total coal, million tonnes)	6 708
Production (total coal, million tonnes, 2005)	202.8

The German Federal Institute for Geosciences and Natural Resources (BGR) has reported coal reserves on behalf of the German WEC Member Committee. Proved recoverable reserves are given as 6 708 million tonnes, most of which is lignite. The level of hard coal reserves in this category is confined to the projected amount of the (highly subsidised) German hard coal production until 2012, there being no clear governmental position (in particular, re financing) regarding output after 2012. The proved amount in place is also based on BGR data; the hard coal component has a maximum deposit depth of 1 500 m below the surface, and a minimum seam thickness of 0.6 m, whilst the corresponding parameters for lignite are 500 and 3 m, respectively.

BGR's category 'resources' (using its own definition, which differs from WEC usage) amounts to around 8.4 billion tonnes of hard coal and 76.4 billion tonnes of lignite. These levels convey an indication of the enormous size of the additional amounts of coal 'in place', over and above the in-situ tonnages hosting the recoverable reserves.

Germany's output of hard coal has fallen from 76.6 million tonnes in 1990 to 24.9 million tonnes in 2005, whilst lignite production has virtually halved, from 357.5 to 177.9 million tonnes over the same period. Germany is still the world's largest lignite producer.

The Ruhr coalfield produces over three-quarters of German hard coal. The coal qualities range from anthracite to high-volatile, strongly-caking bituminous coal. The Saar is the second largest coalfield, with substantial deposits of weakly-caking bituminous coal. All German hard coal is deep-mined from seams at depths exceeding 900 m.

The lignite deposit in the Rhine region is the largest single formation in Europe. In the former East Germany there are major deposits of lignite at Halle Leipzig and Lower Lausitz; these have considerable domestic importance.

The principal markets for bituminous coal are electricity generation, iron and steel, and cement manufacture: other industrial and household uses are relatively modest. The bulk of German lignite is consumed in power stations, although a considerable tonnage (over 11 million tonnes in 2004) is converted into brown coal briquettes for the industrial, residential and commercial markets.

Greece

Proved recoverable reserves (total coal, million tonnes)	3 900
Production (total coal, million tonnes, 2005)	70.6

Coal resources are all in the form of lignite. Apart from a very small amount of private mining, all production is carried out by the mining division of the Public Power Corporation (DEI). There are two lignite centres, Ptolemais-Amynteo (LCPA) in the northern region of Western Macedonia, and Megalopolis (LCM) in the southern region of the Peloponnese. These two centres control the operations of five open-cast mines; LCPA mines account for nearly 80% of DEI's lignite output. In 2005, LCPA produced 55.45 million tonnes of lignite, LCM 14.44 million tonnes.

A new 330 MW lignite-fired power station at Florina in Western Macedonia came into operation in June 2003. In the lignite-mining areas, there are now eight dedicated power stations (total generating capacity: 5 288 MW), which produce more than two-thirds of Greece's electricity supply. Greece is the second largest producer of lignite in the European Union and the 5th largest in the world.

India

Proved amount in place (total coal, million tonnes)	100 124
Proved recoverable reserves (total coal, million tonnes)	56 498
Production (total coal, million tonnes, 2005)	428.4

Coal is the most abundant fossil fuel resource in India, which is the world's third largest coal producer. The principal deposits of hard coal are in the eastern half of the country, ranging from Andhra Pradesh, bordering the Indian Ocean, to Arunachal Pradesh in the extreme north-east: the eastern States of Chhattisgarh, Jharkhand, Orissa and West Bengal together account for about 77% of reserves. The Ministry of Coal (quoting the Geological Survey of India) states that, in addition to 95.9 billion tonnes of ‘proved resources’ of bituminous coal, there are 119.8 billion tonnes of ‘indicated resources’ and 37.7 billion tonnes of ‘inferred resources’. Coking coals constitute 17% of the tonnage of proved resources. The resources quoted are the result of exploration down to a depth of 1 200 m.

The Indian WEC Member Committee reports proved recoverable reserves as 52 240 million tonnes of bituminous coal at end-2005 and 4 258 million tonnes of lignite at end-2004.

Lignite deposits mostly occur in the southern State of Tamil Nadu. India's geological resources of lignite are estimated to be some 36 billion tonnes, of which about 2.4 billion tonnes in the Neyveli area of Tamil Nadu are regarded as ‘mineable under the presently adopted mining parameters’. Annual production of lignite is currently in the region of 31 million tonnes, almost all of which is used for electricity generation.

Although India's coal reserves cover all ranks from lignite to bituminous, they tend to have a high ash content and a low calorific value. The low quality of much of its coal prevents India from being anything but a small exporter of coal (traditionally to the neighbouring countries of Bangladesh, Nepal and Bhutan) and conversely, is responsible for sizeable imports (around 20 million tonnes/yr of coking coal and 17 million tonnes/yr of steam coal) from Australia, China, Indonesia and South Africa.

Coal is the most important source of energy for electricity generation in India: about three-quarters of electricity is generated by coal-fired power stations. In addition, the steel, cement, fertiliser, chemical, paper and many other medium and small-scale industries are also major coal users.

Indonesia

Proved amount in place (total coal, million tonnes)	12 466
Proved recoverable reserves (total coal, million tonnes)	4 328
Production (total coal, million tonnes, 2005)	152.2

Indonesia possesses very substantial coal resources: according to the data reported by the Indonesian WEC Member Committee for the purpose of this *Survey*, the proved amount in place is nearly 12.5 billion tonnes, within which proved recoverable reserves amount to around 4.3 billion tonnes. Sub-bituminous coals account for 40% of the tonnage in place, with lignite 32% and bituminous grades 28%. On a proved recoverable basis, however, bituminous and sub-bituminous each has a share of around 40%.

The Member Committee also reports an estimated additional amount in place of 44.7 billion tonnes, within which 6.0 is classified as bituminous, 27.6 as sub-bituminous and 11.1 as lignite.

Indonesian coals in production generally have medium calorific values (5 000 - 7 000 kcal/kg or 21-29 MJ/kg), with relatively high percentages of volatile matter; they benefit from low ash and sulphur contents, making them some of the cleanest coals in the world.

Competitive quality characteristics have secured substantial coal export markets for Indonesia: it is now the world’s second largest coal exporter, after Australia. In 2005, 108 million tonnes were shipped overseas, representing 71% of total coal output. Asian customers take a large part of Indonesia's coal exports.

Within Indonesia, coal's main market is power generation, which accounted for 63% of internal consumption in 2004.

Kazakhstan

Proved recoverable reserves (total coal, million tonnes)	31 300
Production (total coal, million tonnes, 2005)	86.6

Reported recoverable reserves of some 31 billion tonnes indicate that Kazakhstan has the third largest coal endowment in Asia. Most of these reserves are said to consist of anthracitic and bituminous grades. In the absence of any further data, lignite has, for the purpose of this *Survey,* been assumed to represent 10% of the republic’s total proved reserves.

The major coal-producing areas are the Karaganda Basin towards the centre of the country and the Ekibastuz Basin in the northern province of Pavlodar. Bogatyr Access Komir, Kazakhstan’s largest coal producer, is developing the Bogatyr and Severny fields in the latter basin.

Total national output of coal exhibited a declining trend after independence in 1991, but has recovered some lost ground since the turn of the century. Production in 2005 was 86.6 million tonnes, marginally less than in 2004, with hard coal grades accounting for some 95%. Kazakhstan is a major coal exporter (26 million tonnes in 2004), with Russia and Ukraine as its main customers. The prime internal markets for Kazakh coal are power/CHP plants and the iron and steel sector.

Pakistan

Proved amount in place (total coal, million tonnes)	3 303
Proved recoverable reserves (total coal, million tonnes)	1 982
Production (total coal, million tonnes, 2005)	4.6

At the request of the Pakistan WEC Member Committee, the Geological Survey of Pakistan (GSP) has provided details of coal resources and reserves as at 30 June 2005 (detailed data on reserves/resources 'as on June 30, 2006' issued by the GSP are unchanged from the year before). The total resource is put at more than 186 billion tonnes, within which 'measured reserves' are 3.3 billion tonnes, 'indicated reserves' about 12 billion tonnes, 'inferred reserves' 56 billion and 'hypothetical resources' 114 billion. Clearly a high proportion of the quoted total resource has, at this point in time, a relatively low degree of geological assurance, being comprised of inferred reserves (lying within a radius of 1.2 to 4.8 km from a point of coal measurement) and hypothetical resources (undiscovered coal, generally an extension of inferred reserves in which coal lies more than 4.8 km from a point of measurement). A recovery factor of 0.6 has been applied to the measured reserves, resulting in estimated recoverable amounts (in million tonnes) of 1 bituminous, 167 sub-bituminous and 1 814 lignite.

The WEC Member Committee reports that the bulk (around 98%) of Pakistan's huge coal resource is found in Sindh Province, in particular the Thar coalfield. The economic coal deposits of Pakistan are restricted to Palaeocene and Eocene rock sequences only.

The coals of Pakistan are high in sulphur and ash contents. The moisture percentage is also high in Sindh coal, especially in the Thar coal. The rank of Pakistani coals ranges from lignite to high-volatile bituminous. The demonstrated Thar coalfield has the largest resources (over 175 billion tonnes) and out of that about 12 billion tonnes are 'demonstrated reserves' (2.7 billion 'measured' and about 9.3 billion 'indicated'). The documented production of coal is 4.59 million tonnes for the year 2005.

Small tonnages of indigenous coal are used for electricity generation and by households, but by far the largest portion is used to fire brick kilns. Just over 1 million tonnes of Australian coking coal is imported each year for use in the iron and steel industry.

Poland

Proved amount in place (total coal, million tonnes)	17 169
Proved recoverable reserves (total coal, million tonnes)	7 502
Production (total coal, million tonnes, 2005)	159.5

The Polish WEC Member Committee has been able to provide revised coal resource assessments, of improved relevance. The proved amounts in place and the corresponding tonnages recoverable now refer solely to those in 'developed deposits', rather than being based on ultimately recoverable amounts.

The latest figures show the proved amount of hard coal in place in 'developed deposits' as 15.3 billion tonnes, on the basis of a maximum deposit depth of 1 000 m and a minimum seam thickness of 1 m; the corresponding level for lignite is about 1.9 billion tonnes, at a maximum deposit depth of 350 m and minimum seam thickness of 3 m. Proved recoverable reserves in such developed deposits consist of 6 billion tonnes of hard coal and 1.5 billion tonnes of lignite.

The estimated additional amounts in place have been derived from Poland's total geological resources of coal (called in Polish terminology 'documented geological resources - category A, B and C'), by deducting the in-place and recoverable amounts in developed deposits specified in the previous paragraph, and adding on forecast additional resources of coal, which are in unexplored extensions of known deposits below 1 000 m and inferred amounts estimated on the results of geological information. The resulting additional tonnages are around 27 billion tonnes of hard coal and 12 billion tonnes of lignite.

Poland's hard coal resources are mainly in the Upper Silesian Basin, which lies in the southwest of the country, straddling the border with the Czech Republic: about 80% of the basin is in Polish territory. Other hard-coal fields are located in the Lower Silesia and Lublin basins.

There are a number of lignite deposits in central and western Poland, with four of the larger basins currently being exploited for production.

The quality of the Upper Silesian hard coals is generally quite high, with relatively low levels of sulphur and ash content. One-third of Poland's proved reserves of hard coal are regarded as of coking quality.

Although output of hard coal has declined during the past 17 years, and especially since 1997, Poland is still one of the world's major coal producers (see Table 1-3), with a 2005 output of 98 million tonnes of hard coal and 62 million tonnes of lignite. The decline in hard coal production reflects a deep restructuring of the industry, with the aim of eliminating the non-profitable mines by a reduction in excess production potential, substantially lower employment levels, elimination of government subsidies, etc.

Apart from Russia, Poland is the only world-class coal exporter in Europe: its total exports in 2005 were nearly 21 million tonnes, of which steam coal accounted for 84% and coking for 16%. Germany, Austria, the United Kingdom and France are currently Poland's largest export markets for coal.

About 64% of inland consumption of hard coal goes to the production of electricity and bulk heat, industrial uses account for 24% and residential/commercial/agricultural uses 12%. Almost all lignite production is used for base-load electricity generation.

Russian Federation

Proved amount in place (total coal, million tonnes)	194 000
Proved recoverable reserves (total coal, million tonnes)	157 010
Production (total coal, million tonnes, 2005)	299.3

The only data on coal resources that the Russian WEC Member Committee was able to provide for the present *Survey of Energy Resources* is based on information released by the Ministry of Natural Resources in May 2006: ‘discovered’ reserves of 194 billion tonnes, which are equated with the proved amount in place of all ranks of coal, and ‘balance’ reserves of more than 200 billion tonnes, which are taken to correspond with the additional amount in place. As the WEC Member Committee has been unable to obtain any more coal resource data, for reasons of confidentiality, the levels adopted for proved recoverable reserves in the present instance are unchanged from those given for end-1996 in the 1998 *Survey of Energy Resources*,

The proved amount of coal in place reported for end-1996 comprised 75.8 billion tonnes of bituminous coal, based on a maximum deposit depth of 1 200 m and a minimum seam thickness of 0.6-0.7 m; 113.3 billion tonnes of sub-bituminous grades (at depths of up to 600 m and minimum thickness 1.0-2.0 m); and 11.5 billion tonnes of lignite (at 300 m and 1.5-2.0 m, respectively).

Proved recoverable reserves were reported as just over 49 billion tonnes of bituminous coal, of which 23% was considered to be surface-mineable and 55% was suitable for coking. Of the 97.5 billion tonnes of proved recoverable reserves of sub-bituminous coal, 74% was suitable for surface mining, while all of the 10.5 billion tonnes of recoverable lignite reserves fell into this category. Overall, about 94 billion tonnes of Russia's proved reserves were deemed to be recoverable by opencast or strip mining.

Russian coal reserves are widely dispersed and occur in a number of major basins. These range from the Moscow Basin in the far west to the eastern end of the Donets Basin (most of which is within Ukraine) in the south, the Pechora Basin in the far northeast of European Russia, and the Irkutsk, Kuznetsk, Kansk-Achinsk, Lena, South Yakutia and Tunguska basins extending across Siberia to the Far East.

The principal economic hard coal deposits of Russia are found in the Pechora and Kuznetsk basins. The former, which covers an area of some 90 000 km^2, has been extensively developed for underground operations, despite the severe climate and the fact that 85% of the basin is under permafrost. The deposits are in relatively close proximity to markets and much of the coal is of good rank, including coking grades. The Kuznetsk Basin, an area of some 26 700 km^2, lies to the east of the city of Novosibirsk and contains a wide range of coals; the ash content is variable and the sulphur is generally low. Coal is produced from both surface and underground mines.

Lying east of the Kuznetsk and astride the trans-Siberian railway, the Kansk-Achinsk Basin contains huge deposits of brown (sub-bituminous) coal with medium (in some cases, low) ash content and generally low sulphur; large strip-mines are linked to dedicated power stations and carbo-chemical plants. The vast Siberian coal-bearing areas of the Lena and Tunguska basins constitute largely unexplored resources, the commercial exploitation of which would probably be difficult to establish.

From a peak of around 425 million tonnes in 1988, Russia's total coal production declined dramatically following the disintegration of the USSR, reaching a low point of around 232 million tonnes in 1998, since when output has regained an upward trajectory, attaining almost 300 million tonnes in 2005. In 2004, around 70% of Russian consumption was accounted for by power stations and district heating plants; the iron and steel industry and the residential sector were the other main centres of coal usage.

Serbia

Proved amount in place (total coal, million tonnes)	21 176
Proved recoverable reserves (total coal, million tonnes)	13 885
Production (total coal, million tonnes, 2005)	35.0

Serbia has Europe's largest proven deposits of lignite. The Serbian WEC Member Committee reports that the proved amount of coal in place is over 21 billion tonnes, of which by far the greater part (97%) is lignite. Within the other ranks, 6 million out of the 27 million tonnes of bituminous coal in place (22%) is deemed to be recoverable, while the corresponding figures for sub-bituminous are 379 million out of 571 million (66%). The recovery factor attributed to the lignite reserves is also approximately 66%.

The pattern of Serbia's coal reserves is replicated in current production levels: lignite (all of which surface-mined) accounted for more than 98% of total output in 2005. Most of the lignite is used for electricity generation, with minor quantities being briquetted or directly consumed in the industrial and residential sectors.

South Africa

Proved amount in place (total coal, million tonnes)	115 000
Proved recoverable reserves (total coal, million tonnes)	48 000
Production (total coal, million tonnes, 2005)	245.0

The South African WEC Member Committee has reported coal resources for the present *Survey* based on an assessment published in 1987, adjusted for cumulative production; they thus differ only marginally from those reported for the 2004 *Survey*.

The proved amount in place relates to a maximum deposit depth of 350 m and a minimum seam thickness of 1 m. The reserve is based on a previous study by the Geological Survey of South Africa (now the Council for Geoscience), completed in 1972 but not published until 1987. While there have been later recalculations of the reserve, these are not yet finalised. If the re-evaluations are found to be correct, the current proved recoverable reserves would be 31 022 mt. However, it is known that significant resources in the Waterberg coal field need to be evaluated and redefined as reserves. These are included as reserves in the 48 000 mt given above but excluded from the figure of 31 022 mt.

The South African Department of Minerals and Energy has initiated a comprehensive survey to re-evaluate the reserve but no report has yet been issued. No information is available as to the progress of the study. What is clear is that South African reserves require an urgent and comprehensive re-evaluation. Alternative exploitation techniques (such as in-situ gasification) may open up currently non-economic resources and thus change the reserve base.

Coal occurs principally in three regions:

- The shaly Volksrust Formation, which covers most of central and northern Mpumalanga province (formerly the Transvaal). The coal is found in isolated basins and troughs which results in the fields being disconnected and widely separated;
- The sandy Vryheid Formation of the northern part of the main Karoo basin (northern Free State, northern Kwazulu-Natal and southern Mpumalanga): this generally continuous area is probably the most important economically;
- The Molteno Formation, which is confined to the north-eastern Cape. It is of minor economic importance compared to other coalfields in South Africa.

Some lignite deposits are known along the Kwazulu-Natal and Cape coasts, but are considered to be of scant economic importance.

Coal occurrences have been divided into 19 separate coalfields, 18 of which are located in an area extending some 600 km from north to south by 500 km from east to west. The Molteno field lies some 300 km south of the main coal-bearing region.

South Africa's coals are generally low in sulphur but high in ash. Beneficiation is essential for export-quality coal. Lower-quality coal is for the local power generation market.

Eskom, the South African electric utility, accounts for about 60% of coal consumption. A further large slice is consumed by the Sasol plants in making synthetic fuels and chemicals from coal. The third main user is the industrial sector, including the iron and steel industry. Coal use in residential and commercial premises is relatively small, while demand by the railways has virtually disappeared.

Coal exports are equivalent to about 30% of South African output and are mainly destined for Europe and Asia/Pacific. The main route for exports is via Richards Bay, Kwazulu-Natal, where there is one of the world's largest coal-export terminals.

Thailand

Proved amount in place (total coal, million tonnes)	2 056
Proved recoverable reserves (total coal, million tonnes)	1 354
Production (total coal, million tonnes, 2005)	21.4

Thailand has sizeable resources of lignite, notably at Mae Moh in the north of the country. For the 2004 SER, the Thai WEC Member Committee reported proved recoverable reserves of 1 354 million tonnes; the maximum deposit depth taken into consideration was approximately 700 m, while the minimum seam thickness was 0.30 m. In respect of the present *Survey*, the Member Committee has reported a proved amount in place for lignite of 2 056 million tonnes, and an estimated additional amount in place of 2 857 million tonnes.

The 2005 edition of the annual publication *Thailand Energy Situation*, issued by the Department of Energy Development and Promotion, quotes total lignite reserves as 2 870 million tonnes. In this context, the reserves are defined as including 'the remaining reserve from produced area as well as the measured and indicated reserve from undeveloped area'.

Annual output of lignite increased by almost 90% between 1990 and 1997, but has since levelled off. All of Mae Moh's production is consumed by the Mae Moh power plant (2 625 MW). On the other hand, most of the lignite produced by other Thai mines is used by industry, chiefly in cement manufacture. Imports of bituminous coal are mostly destined for consumption in the iron and steel sector.

Ukraine

Proved amount in place (total coal, million tonnes)	45 164
Proved recoverable reserves (total coal, million tonnes)	33 873
Production (total coal, million tonnes, 2005)	78.4

Ukraine's coal endowment is one of the largest in Europe. The WEC Member Committee for Ukraine reports that the proved amount of coal in place exceeds 45 billion tonnes, of which 45% ranks as bituminous, 49% as sub-bituminous and about 6% as lignite. The reported mining parameters associated with these resource assessments are (respectively) maximum depths of 1 800, 1 800 and 400 metres, and minimum seam thicknesses of 0.55, 0.60 and 2.7 metres.

A recovery factor of 75% is attributed to all three ranks, implying proved recoverable reserves of some 15 billion tonnes of bituminous, 17 billion of sub-bituminous and 2 billion of lignite. Most of the bituminous and sub-bituminous deposits are located in the Donets Basin in eastern Ukraine.

Over and above the massive tonnages reported as proved, the WEC Member Committee quotes estimated additional amounts in place totalling more than 11 billion tonnes, with a broadly similar breakdown by rank as for the proved component, and the same implied recovery factor of 75%.

Coal production in 2005 is reported by the Ministry of Coal Industry as just over 78 million tonnes, but without a breakdown by rank. The principal outlets for Ukrainian coal are the iron and steel industry (51% in 2004) and power stations (37%).

United Kingdom

Proved recoverable reserves (total coal, million tonnes)	155
Production (total coal, million tonnes, 2005)	20.5

Coal deposits are widely distributed and for many years the UK was one of the world's largest coal producers, and by far its largest exporter. Production rose to a peak of nearly 300 million tonnes/yr during World War I and thereafter did not fall below 200 million tonnes/yr until 1960. Output began a long-term decline in the mid-1960s, falling to less than 100 million tonnes/yr by 1990. Reflecting continued competition from natural gas and imported coal, UK coal production sank to just over 20 million tonnes in 2005, including coal/slurry recovered from non-mine sources such as dumps, ponds, rivers, etc.

The UK coal industry was privatised at the end of 1994, with the principal purchaser being RJB Mining (now UK Coal plc), which acquired 16 deep mines from British Coal. At 31 March 2006 there were 7 major deep mines, 5 smaller deep mines and 35 open-cast sites in production. Deep-mined coal output in 2005 was 9.56 million tonnes and open-cast sites produced 10.45 million tonnes – the first year that the output from UK deep mines had fallen below that of open-cast sites. Production from slurry etc. amounted to 0.49 million tonnes. There is now virtually no UK production of coking coal – output in 2005 was only 274 000 tonnes.

The decline of the British coal industry has been accompanied by a sharp decrease in economically recoverable reserves. The figure reported by the United Kingdom WEC Member Committee for the purpose of the present *Survey* is 155 million tonnes, reflecting the 2006 level (comprising 110 in deep mines and 45 in surface mines), quoted in Chapter 4 of *The Energy Challenge: Energy Review Report 2006*, published by the UK Department of Trade and Industry in July 2006. The DTI figures are described as ‘estimates of deep and surface mine reserves identified in reviews commissioned by DTI in 1998-2004 adjusted to reflect subsequent mine closures and production and the uprating of newly proved reserves at ongoing mines’. The report goes on to say that ‘in addition to this, there is thought to be in the order of 400 million tonnes of recoverable coal at other prospects, most of which would require either new mine developments or significant investment at existing or former mines’.

The coal resources of the UK are, of course, considerably larger than the comparatively modest levels of recoverable reserves quoted for existing deep mines and opencast sites. The Coal Authority, the body responsible for directing the British coal industry, has indicated that in 2005 coal resources at existing deep mines and existing, planned and known potential surface-mining sites were in the order of 900 million tonnes, with approximately one-third in deep mines and two-thirds at surface-mining sites. Additional recoverable tonnages considered to be potentially available from new or expanded deep-mining operations amounted to almost 1.4 billion tonnes.

The Government White Paper, *Meeting the Energy Challenge* (May 2007) states that, ‘Making the best use of UK energy resources, including coal reserves, where it is economically viable and environmentally acceptable to do so contributes to our security of supply goals. The Government believes that these factors reflect a value in maintaining access to economically recoverable reserves of coal’.

United States of America

Proved amount in place (total coal, million tonnes)	447 183
Proved recoverable reserves (total coal, million tonnes)	242 721
Production (total coal, million tonnes, 2005)	1 038.6

The United States coal resource base is the largest in the world. The US WEC Member Committee reports a proved amount in place at 1 January 2006 of some 447 billion tonnes (based on the Energy Information Administration's ‘Demonstrated Reserve Base’). This total is comprised of 244.3 billion tonnes of bituminous coal (including anthracite) with a maximum deposit depth of 671 m and minimum seam thickness of 0.25 m; 163.6 billion tonnes of sub-bituminous (at up to 305 m depth and 1.52 m minimum seam thickness) and 39.3 billion tonnes of lignite (at up to 61 m depth and 0.76 m minimum seam thickness).

The reported proved recoverable reserves amount to 242.7 billion tonnes, equivalent to about 29% of the global total. They comprise 112.3 billion tonnes of bituminous coal (including anthracite), 100 billion tonnes of sub-bituminous and 30.4 billion tonnes of lignite. The overall ratio of proved recoverable reserves to the proved amount in place is 0.54. This ratio varies widely from one rank to another, reflecting relative degrees of accessibility and recoverability: bituminous deposits average 0.46, sub-bituminous 0.61 and lignite 0.77. Open-cast or surface mining techniques can be applied to 27% of bituminous reserves, to 43.4% of the sub-bituminous and to 100% of the lignite.

Data for proved amount in place and recoverable reserves are measured and indicated (proved and probable), in a commingled data base. The data cannot be separated into 'proved only' and 'probable only'.

On top of the tonnages summarised above, the US WEC Member Committee reports enormous quantities of coal as 'estimated additional amounts in place': in total these come to well over a trillion tonnes, composed of 445 billion tonnes of bituminous, 274 billion sub-bituminous and 394 billion lignite. These estimates are derived from a US Department of the Interior study of coal resources as at 1 January 1974, but are regarded as still providing valid indications of the magnitude of the USA's additional coal resources. Data on the estimated additional amount in place are primarily inferred. These resources extend deeper than the proved amount in place, include thinner beds in some areas, and are based on older source data in many cases. The estimated additional amount in place has been adjusted only to indicate the arithmetic difference with proved amount in place.

Coal deposits are widely distributed, being found in 38 states and underlying about 13% of the total land area. The Western Region (owing largely to Montana and Wyoming) accounts for about 47% of the EIA's ‘Demonstrated Reserve Base’, the Interior Region (chiefly Illinois and western Kentucky) for 32% and the Appalachian Region (chiefly West Virginia, Pennsylvania and Ohio) for 21%. Bituminous coal reserves are recorded for 27 states, whereas only 8 states have sub-bituminous reserves, of which 90% are located in Montana and Wyoming, and 10 have lignite reserves, mostly in Montana and Texas.

US coal output is the second highest in the world, after China, and accounted for about 18% of global production in 2005. Included in the USA’s 2005 coal production of 1 038.6 million tonnes is 12.1 million tonnes of recovered waste coal. Coal is the USA's largest single source of indigenous primary energy; power stations, CHP and heat plants accounted for 82% of domestic coal consumption in 2004. Coal exports amounted to 45 million tonnes in 2005: the USA remains a leading supplier of coking coal and other bituminous grades.

Uzbekistan

Proved recoverable reserves (total coal, million tonnes)	3 000
Production (total coal, million tonnes, 2005)	3.2

Most of the republic’s coal resources are classed as brown coal or lignite. Uzbek sources quote the proved (sometimes referred to as ‘commercial’) coal reserves as approximately 3 billion tonnes, of which 1 billion is classed as bituminous (or ‘fossil’) coal.

Two lignite fields are presently being developed: the Angren strip-mine in the Tashkent region and the Shargun deposit in the Surkhandarya region. Some bituminous coal is produced from the Baysun field, also in the southern region of Surkhandarya.

Reflecting a modernisation programme at Angren, Uzbekistan’s lignite production has increased in recent years, exceeding 3 million tonnes in 2005. Bituminous output remains on a very small scale (around 70 000 tpa). In 2004, about 82% of lignite production was consumed in power stations and CHP/heat plants.

2. Crude Oil and Natural Gas Liquids

COMMENTARY

Reserves and Resources

Defining what to Measure

There are several different categories of oil, each having different costs, characteristics and, above all, depletion profiles. Some are easy, cheap and fast to produce, whereas others are the precise opposite.

The terms ‘Conventional’ and ‘Non-Conventional’ (or ‘Unconventional’) are in wide usage, but lack a standard definition, adding greatly to the confusion. Here, ‘Conventional Oil’ will be identified and defined to exclude the following categories: oil from coal, shale, bitumen and Extra-Heavy Oil.

Besides this, ‘Reserves’ are differentiated from ‘Resources’. ‘Reserves’ are the amount currently technologically and economically recoverable. ‘Resources’ are detected quantities that cannot be profitably recovered with current technology, but might be recoverable in the future, as well as those quantities that are geologically possible but yet to be found.

Editors' Note:

The discussion of oil reserves and resources in the Oil Commentary uses the terminology of the Bundesanstalt für Geowissenschaften und Rohstoffe (BGR). This differs to some extent from the standard WEC terminology used in the remainder of this chapter. The following broad equivalences should be borne in mind:

BGR Term	WEC Term
Reserves	Proved Recoverable Reserves
Resources	Estimated Additional Reserves Recoverable
Estimated Ultimate Recovery (EUR)	Proved Recoverable Reserves + Estimated Additional Reserves Recoverable + Cumulative Production
Remaining Potential	Proved Recoverable Reserves + Estimated Additional Reserves Recoverable

State of the Art

In terms of global consumption, crude oil remains the most important primary fuel, accounting for 36.4% of the world's primary energy consumption (without biomass) (BP, 2006). Forecasts (e.g. IEA, 2005, 2006) of the development of energy consumption imply that there will be no significant change in the importance of oil in the next few decades.

The 'estimated ultimate recovery' (EUR) of conventional crude oil was about 387 billion tonnes at the end of 2005. This amount is higher than the amount of 381 billion tonnes given in the 2005 energy study (BGR, 2006). The regional distribution of 'estimated ultimate recovery' of conventional crude oil, comprising cumulative production, reserves and resources, is very uneven (Fig. 2-1). The Middle East has the highest EUR. About 65% of North America's EUR has been recovered so far. In the CIS countries, this applies to about 37 % and in the Middle East to about 24% of the EUR. The OPEC countries have an EUR of about 206 billion tonnes, accounting for more than 50 % of the global EUR, of which only about 28% has been recovered so far. The OECD countries have an EUR of only 74 billion tonnes, of which nearly 62% has already been recovered.

Global crude oil reserves increased slightly from 2004 by 2 billion tonnes to about 162[1]. This increase in reserves results mainly from a higher assessment of known fields and only to a small extent from the discovery of new fields. About 62% of the global reserves are located in the Middle East, about 13% in North and South America and about 10% in the CIS countries.

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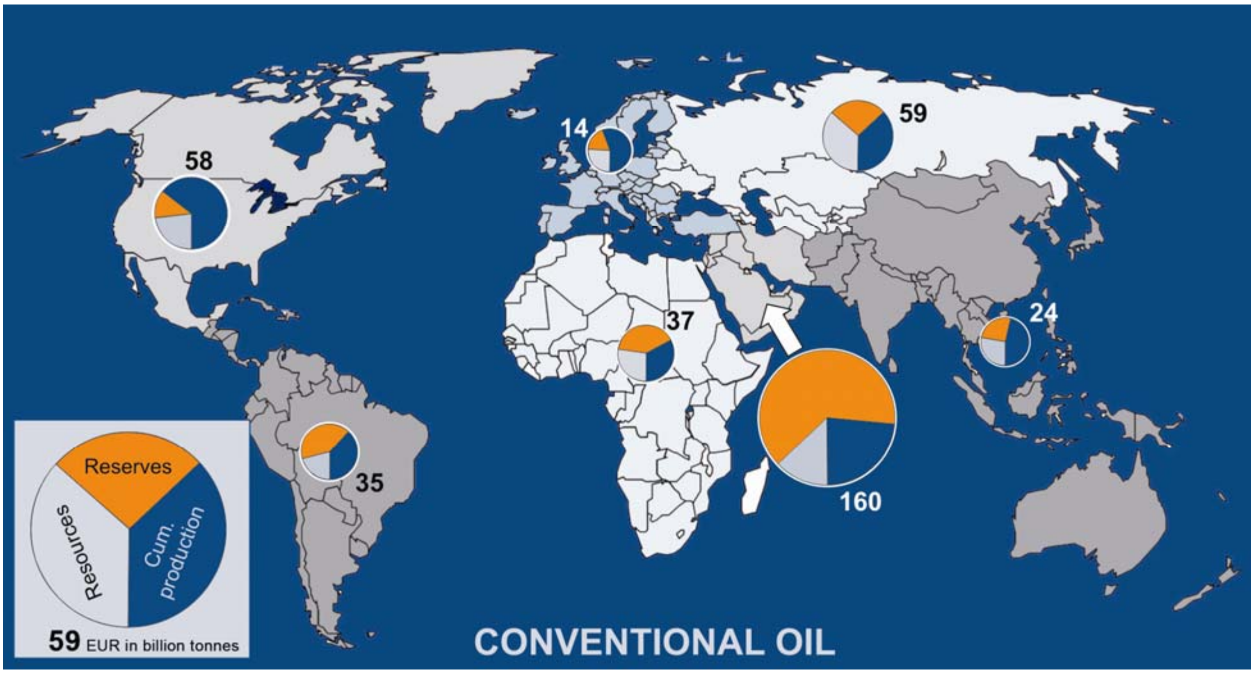
[1] The difference between BGR's reserves and the corresponding level given in Table 2.1 is essentially due to the conversion factors used to convert from volumetric data.

Figure 2-1 Distribution of the estimated ultimate recovery of conventional crude oil in 2005
Source: BGR, 2006



The OPEC countries have about 76% of global reserves (of which 61% is to be found in the Persian Gulf region), the OECD about 7%, leaving about 18% for the rest of the world.

Global crude oil production increased only moderately till 2003. In 2004 and 2005, there was a significant increase up to 3 900 mt - anew absolute production maximum. The regions with the highest production in 2005 were the Middle East, North America and the CIS countries.

Cumulative crude oil production until the end of 2005 reached 143 billion tonnes - half of it was produced within the last 23 years. This means that 47% of the total reserves of conventional oil discovered so far has been consumed. Taking into consideration also the expected resources of 82 billion tonnes, more than 37% of the EUR has been consumed. The depletion mid-point - when half of the EUR will have been recovered - will be reached within the next 10 to 20 years. Afterwards, the decline of conventional oil production is inevitable.

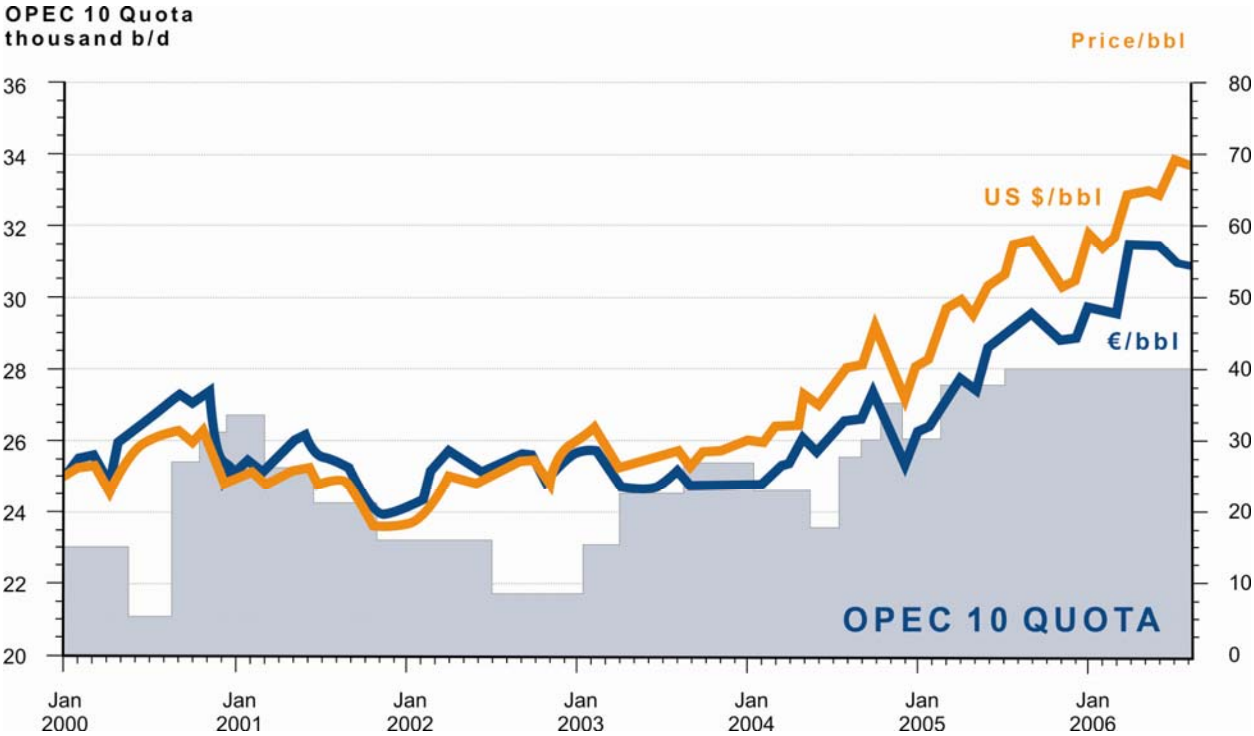
About two-thirds of the crude oil produced in 2005 was transported between different countries and regions, sometimes covering large distances by tanker or pipeline. For crude oil, there is a single global market with nearly uniform prices. However, there was a significant increase in price differentials between oils of different quality due to a general increase in oil prices.

Oil prices increased sharply in the last three years and reached their short-term maximum in August 2006 at nearly US$ 79/bbl for Brent crude. In real terms (taking inflation into account), this price is somewhat below the historical maximum of about US$ 80/bbl at the end of 1979. In terms of the Euro, this development is slightly more moderate.

The reasons for the currently very high oil price, which in nominal terms is much higher than after the oil price crises in 1973 and 1979, are interpreted differently. Some experts regard an imminent shortage of oil reserves (peak oil discussion) as the driving force. Others consider that a combination of different factors is most likely to be the reason for this development. Among these factors are:

- increasing worldwide demand for oil, after some years of stagnation, caused by

Figure 2-2 Development of monthly average prices for OPEC basket of crude oil in US$ and Euro per barrel and changes in OPEC-10 production quotas
Source: BGR, 2006



prospering economies and strong demand for oil in the USA, China and India;

- supply disruptions caused by strikes in leading supplier countries (Venezuela, Nigeria, Norway) and terrorist attacks in Iraq, as well as natural disasters (e.g. hurricanes in the Gulf of Mexico);
- political instability in the Middle East and the Yukos affair in Russia, as well as a fear of terrorist attacks;
- lack of additional production capacity in most of the producing countries;
- the weak US Dollar;
- speculation in the oil business due to low interest rates on the capital markets.

To summarise, the following developments can be expected for crude oil in the future:

- From a geological point of view, the remaining potential for conventional oil can provide for a moderate increase in oil consumption over the next 10 to 15 years. After that, an insufficient supply may be expected, owing to decreasing production when the depletion mid-point has been passed. Demand will then have to be met by other fuels. The percentage of oil production by the OPEC countries (especially in the Persian Gulf region) will increase for several decades to come.
- The percentage of non-conventional oil will rise to 5-10% of total oil production by 2020, as oil prices will stay at relatively high levels. In its *International Energy Outlook 2006*, the US Energy Information Administration (EIA, 2006) predicted the share of non-conventional oil in world oil consumption as 9.7% in 2030, including synthetic fuels from natural gas (GTL), coal (CTL) and biomass (BTL), whereas the IEA predicts a share of 8.9% in 2030 of non-conventional oil in its *World Energy Outlook 2005*, with synthetic fuels providing 22.5% of non-conventional oil.

Figure 2-3 Resources/Reserves ratio (RRR) as an indicator of the future availability of conventional geo-fuels at end-2005
Source: data after BGR, 2006

Fuel	Resources		Reserves		RRR
Oil, conventional	82	bill. tonnes	162	bill. tonnes	0.5
Natural Gas, conventional	207	trillion m³	179	trillion m^3	1.2
Hard Coal	4 079	bill. tonnes	746	bill. tonnes	5.5
Brown Coal/Lignite	1 025	bill. tonnes	207	bill. tonnes	5.0
Uranium *	12.8	mill. tonnes	1.9	mill. tonnes	6.8

* Reserves based on 'Reasonably Assured Reserves' at up to US$ 40/kgU

- Predicting oil price fluctuations is very difficult, owing to a variety of factors. Important factors influencing their development are likely to be the behaviour of OPEC countries, the availability of additional production and refining capacities, as well as the development of the global economy. Daily fluctuations in crude oil prices up to a range of several US$ per barrel are likely in both directions, owing to speculation in the oil market business.
- There are numerous uncertainties that could possibly affect the availability of crude oil:
- the R/P ratio could possibly be shortened by a downward revision of OPEC reserves. These reserve numbers were sharply boosted in the 1980s, presumably for political reasons in order to keep OPEC production quotas in balance;
- the R/P ratio can be lengthened due to uncertainties in reserve assessment. Proved reserve figures do not normally include probable and possible reserves.

As a rough indicator of the future availability of geo-energy fuels, the ratio of resources (in the BGR sense of additional reserves) to (proved) reserves can be used (Fig. 2-3). The larger the indicator, the more 'resources' can be converted into 'reserves'.

A Contribution to the Peak Oil Discussion

Introduction

The Industrial Revolution was born in the 18th Century when countries tapped into their coal resources as a new and convenient source of energy to fuel industry and transport, along with the subsequent development of the railway system.

Oil seepages on the earth's surface had been known from antiquity, being locally exploited in shallow hand-dug wells. Then in 1859, drilling technology, already in place for the extraction of salt-brine, was adapted to drill for oil in Pennsylvania, and a shallow deposit, at a depth of 67 feet, was found. This small step led to the growth of one of the world's largest industries, which began to deliver increasing amounts of this cheap and convenient source of energy, leading to the rapid expansion of industry in general, together with transport, trade and agriculture, which allowed the world's population to expand six-fold over the next 150 years. This chapter of history also saw the rapid expansion of financial capital, as banks lent more than they had on deposit, confident that *Tomorrow's Expansion* was collateral for *Today's Debt*, without necessarily recognising that it was the abundant supply of largely oil-based energy that made the expansion possible. In short, the world changed greatly over what has been described as the *First Half of the Age of Oil.*

Oil and gas were formed in the geological past, meaning that they are natural resources subject to depletion. Therefore it is time to take stock of

The world will not finally run out of oil for very many years, if ever, but the onset of decline may prove to be a discontinuity of historic proportions.

the situation and try to determine the status of depletion. Knowledge of the physical conditions for oil generation has improved greatly, meaning that the search for oil can now be driven by scientific principles, although speculative projects are still sometimes undertaken. In practice, the oil industry has searched the world, always looking for the biggest and best prospects, and it has generally enjoyed a favourable economic climate, insofar as even small discoveries are highly profitable and much of the cost of exploration can be written off against taxable income. Given that there is a finite limit, past success means that there is less and less left to find in the future. The industry has made remarkable technological progress, such that it has become routine to drill 5 000 m wells in the stormy waters of the North Sea. But there is a certain irony in that improvements in technology have tended to increase extraction rates, thereby accelerating depletion (unless counterbalanced by enhanced recovery).

Lastly it is axiomatic to state that oil has to be found before it can be produced, which means that the discovery profile has to be mirrored in the production profile after a time lapse. If the peak in world discovery occurred in the 1960s, as the data appear to suggest, it follows that a corresponding peak in production may be imminent. The word *appear* is used advisedly, because great difficulties are experienced in interpreting the data as a result of differing reporting practices and ambiguity in defining the different categories to measure. These two subjects need to be addressed carefully before coming to an assessment of the status of depletion.

As will be explained more fully below, it is important to recognise, first, that there is an *Oil Age*, which in fact promises to be a relatively brief chapter of human history; and second that inevitably the *Oil Age* is divisible into a *First Half*, when discovery and production rise; and a *Second Half*, when they decline. The world will not finally run out of oil for very many years, if ever, but the onset of decline may prove to be a discontinuity of historic proportions, given the key role oil plays in modern economies. The transition to decline threatens indeed to be an age of great economic and geopolitical tension.

Reporting Production and Reserves

At first sight, it might seem a straightforward task to assess the size of an oilfield and report its production, but in fact reporting practices range widely and are subject to much misunderstanding and confusion.

Production Reporting

The reporting of oil production is relatively straightforward in many countries, although it is effectively a state secret in some places, even relying on no more than the reports of shipping agents, counting tankers leaving the terminals. Domestic consumption in such countries may also be inaccurately reported. There are in addition a number of factors affecting the reports, including those listed below:

- **war loss:** battles have been fought over oilfields, in some cases leading to the escape of oil. Such loss is to be considered production in the sense that it reduces the reserves by a like amount. Some 2 billion barrels of Kuwaiti crude was probably lost in this way during the Gulf War;

- **metering:** in some cases, production from several fields is metered together at a central facility, such that the production of the individual component fields may not be readily identifiable. This is the case, for example, with respect to several of the Lake Maracaibo fields in Venezuela;

- **gas liquids:** liquids commonly condense from natural gas at surface conditions of temperature and pressure, being termed *condensate*. This may be either metered separately or fed back into the gas or oil streams.

- **operating fuels**: in some cases gas, condensate and even oil are used as an operating fuel, and not metered. Spillage likewise cannot be counted.

It should be noted in addition that *production* is not synonymous with *supply*, namely the amount available for consumption. Refinery gains (running at 2-3%) have to be added and losses in storage and transportation taken into account.

These distortions are however relatively minor compared with those associated with the reporting of reserves, which deserve to be explained more fully.

Reserve Reporting

The traditional industry classification of reserves, arising from the early days in the United States, was to recognise 'Proved',' Probable' and 'Possible' categories, with the meanings the words normally convey. The mineral rights in the United States mainly belong to the landowner, which means that individual fields were physically divided, even to the extent in some cases of separate reservoirs having separate owners. Oil in the ground was a financial asset against which money could be borrowed, leading the Securities and Exchange Commission (SEC) to introduce strict rules, which were designed to prevent fraudulent exaggeration, while smiling on under-reporting as commercial prudence. It recognised two prime categories, namely 'proved developed' for the anticipated future production of current wells and 'proved undeveloped' for the expected production from infill wells between the existing ones, before they have actually been drilled.

It was a perfectly sound system for the circumstances for which it was designed, but it was also adopted by the international oil companies, which were quoted on the American exchanges, although the circumstances were rather different, including in some cases greater commercial uncertainty. It made good sense for the companies to under-report discovery and then revise the reports upwards over time, which gave a comforting but misleading image of steady growth. The larger fields were normally developed in phases, with each phase being reported as it was committed. The upward revisions were termed 'reserve growth', which was widely attributed to technological progress, when in fact it was in large measure simply an artefact of reporting. But as the stock of ageing large fields declined, so did the scope for under-reporting, with many of the smaller fields being developed in a single phase, in some cases even delivering disappointing results. Accordingly it is unlikely that the apparent 'reserve growth' of the past will be matched in the future.

Estimating the size of an oilfield early in its life poses no particular technical challenge, though it is subject to a degree of uncertainty. This in turn prompted some analysts to apply Probability Theory to the issue. Under this system, alternative reserve estimates are plotted against a range of subjective probability rankings. It is common to refer to P_{95} Reserves, such being deemed to have a 95% probability of exceeding the stated value, and P_5 Reserves for those with a 5% probability of doing so. From this range, median (P_{50}) and mean values are computed.

The 'best estimates' so-to-speak of future production are described under the alternative systems as proved + probable or as having a mean or median (P_{50}) probability ranking. As may be imagined, there are plenty of grey areas in the application of these systems, with a general tendency for the international companies to report cautious estimates subject to upward revision, as already noted.

There are in addition what may be described as political reserves, especially amongst the OPEC countries, which found themselves competing for production quotas based in part on reported reserves. There is some evidence to suggest that some of these countries started reporting 'original' not 'remaining reserves' during the 1980s at a time of weak oil price, while others simply aimed to match or outshine the reports of their neighbours. It would explain why the reports in some countries, as for example Abu Dhabi, have since barely changed, despite production in the meantime: it being clearly implausible that new discovery would exactly match production. It might indeed have made good sense from the standpoint of quota negotiations to have a stable number unaffected by production.

Lastly, the former Soviet Union had its own system, based on an alphabetical classification with various subdivisions. The categories A + B + C1 are widely considered equivalent to the 'proved' + 'probable reserves' of the SEC classification, but decline studies of individual fields suggest that in fact they exaggerate by about 30%.

Another misleading practice is the uncritical use of Reserves-to-Production Ratios (R/P), quoted in years, whereby the indicated reserves are divided by annual production to suggest a given life-span. It is clearly absurd to postulate that production could stay flat for a given number of years and then stop dead, when all oilfields are observed to decline gradually. Still another unfortunate practice is to produce forecasts of supply and demand over relatively short spans, evading the implication that production would have to collapse immediately after the forecast period, if it were to respect the resource constraints.

The scale of confusion arising from the differing systems of classification and definition is self-evident, meaning that the various public and industry databases record widely different estimates. The principal public databases are those published annually by the *Oil & Gas Journal* and *World Oil*, which are based on questionnaires sent out to governments and industry around the world. As trade journals, they are not in a position to assess the validity of the information they receive. In addition, proprietary industry databases exist, principally those produced by IHS Energy and Wood Mackenzie. In earlier years, the former was compiled through close, albeit informal, cooperation with the major companies, but the task has become much more difficult as a result of the proliferation of small promotional companies and the growing role of State companies with a political agenda. There are also the data bases published by the oil companies BP and ENI, which are compilations from other sources, mostly not reflecting the company's own knowledge. Lastly, there is the present *Survey*, which brings together information provided by the WEC Member Committees, supplemented by other data obtained from governmental or industry sources.

Modelling Depletion

Notwithstanding the many uncertainties regarding the validity of the data, it remains very important to make an attempt to establish the status of depletion by country, region and eventually for the world as a whole, so that governments may be in a position to adopt policies to prepare for the *Second Half of the Age of Oil,* when production and all that depends on it declines, owing to natural constraints that lie beyond economic or political influences. The objective should clearly be to establish a sound working model, while remaining prepared to revise and improve it, if and when greater knowledge and insight materialise. The steps to be undertaken in such a process can therefore be outlined. It is helpful to start with countries reporting more reliable data to establish the procedure, before facing the more difficult cases.

Step 1. Collect information on discovery by field, backdating any reserve revisions to the date of the original discovery, and collect information on exploration drilling. Plotting cumulative discovery against cumulative exploration drilling will produce a clear trend, which is normally hyperbolic because the larger fields are generally found first. Extrapolating the trend to an asymptote gives a good indication of the total to be produced in the country concerned (termed 'ultimate recovery'), subject to an economic cut-off for very small fields.

Step 2. Collect information on past production and plot (annual divided by cumulative) against

Figure 2-4 United Kingdom discovery trend
Source: UK Department of Trade and Industry

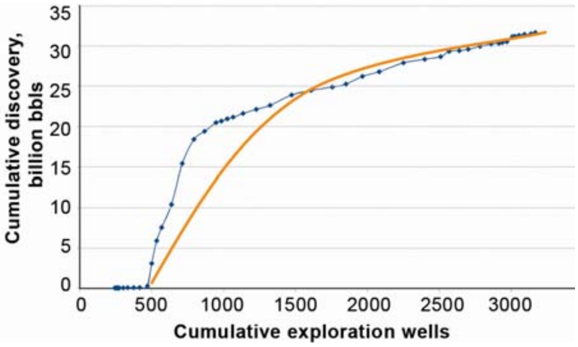
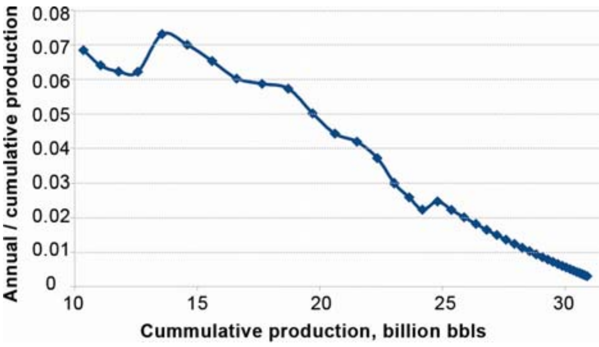


Figure 2-5 United Kingdom derivative logistic
Source: UK Department of Trade and Industry



cumulative (the so-called derivative logistic plot) and extrapolate to zero, which also corresponds with the total oil endowment. In some countries, this plot delivers a firm trend that can be extrapolated confidently, but that is not always the case. Being based solely on relatively reliable production data, it avoids the uncertainties arising from unreliable reserve reporting.

Step 3. Having established the total in Steps 1 and 2, subtract past production to deliver future production, which is divided into that coming from known fields (reserves) and that derived from new discovery. It is convenient to apply a percentage factor to deliver the reserve estimate such as to bear a reasonable relationship to the range of reported reserves, after deduction of any non-conventional categories. One option would be to take the average of the range, but on balance it is better to study the matter, so as to exclude any report that would otherwise distort the calculation of an average.

Step 4. Enter production, exploration drilling and discovery in a table, and calculate the depletion rate, being annual production as a percentage of what is left. This normally ranges from about 3% to 8%. If it were higher, there would be a case for re-examining the estimate of the ultimate recovery, which could be raised in order to deliver a more plausible depletion rate.

Having input the essential data into the model, it is time to forecast future production. In this regard, it is expedient to recognise three different categories of country as follows:

Post-Midpoint Countries

This group comprises those countries that have already produced more than half their indicated ultimate recovery, and are already in marked decline. Future production can be modelled on the assumption that it declines at the current depletion rate, namely in the range of 3-8% per year.

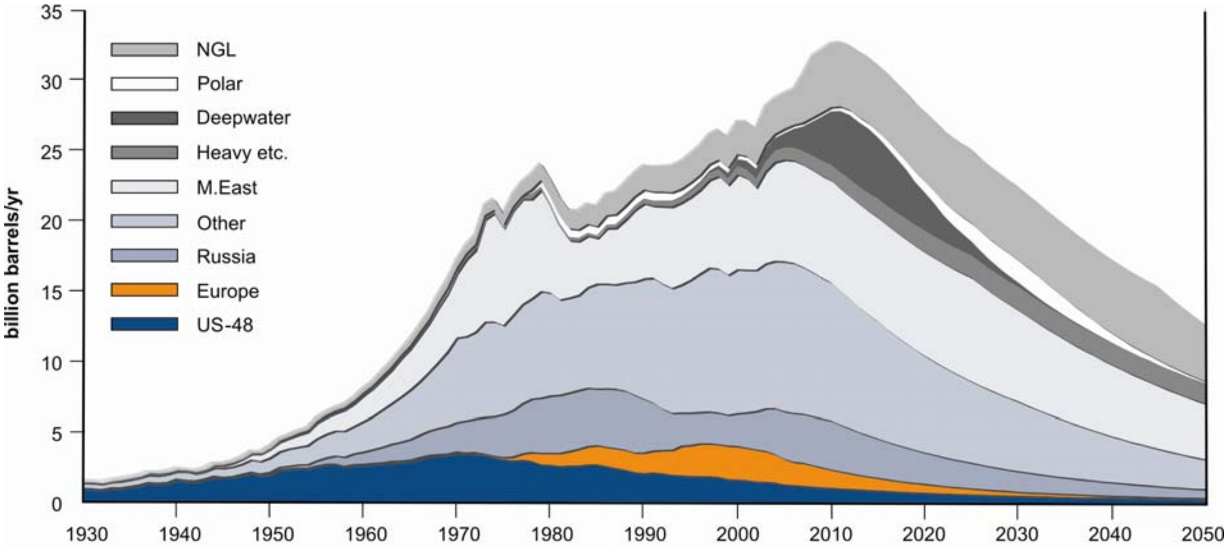
Pre-Midpoint Countries

This group refers to those countries that have not yet reached their midpoint. Production has therefore to be assessed on the basis of the prevailing local circumstances, possibly being assumed to rise on the past trend to midpoint. On reaching midpoint it is assumed that production declines at the then depletion rate. Since most such countries are in fact within a few years of midpoint, the assumptions are not particularly critical to the overall model.

Middle East Gulf

This group comprises Abu Dhabi, Iran, Iraq, Kuwait, the Neutral Zone and Saudi Arabia, and presents the greatest uncertainty. They are major producers with exceptionally low depletion rates, meaning that, in resource terms, production could rise substantially. However in political terms, it seems reasonable to assume that they will prefer to hold production at current levels in order to maintain prices and to reduce the rate of depletion. They rely heavily on oil revenue and have good reason to adopt policies to make it last as long as possible. It would

Figure 2-6 Production profile of oil and gas liquids
Source: 2006 Scenario, Association for the Study of Peak Oil & Gas, 2007



make sense therefore to assume that production in these countries will remain flat until the depletion rate rises to say 3% before the onset of terminal decline. Iraq is a special case, offering the possibility that production might rise to a more normal plateau should the political situation permit. There are alternative ways in which to address this group, for example treating them as swing producers, making up the difference between world demand and what the other countries can supply, but on balance the indications are that natural and investment constraints have limited their swing roles.

Evaluation

The various public reserve data illustrate, amongst other things, the wide range of estimates. The analyst producing a depletion profile will naturally take full note of these assessments, comparing them with such proprietary or confidential information as may be in his possession, in order to arrive at what seems to be a plausible and reasonable estimate. This is not an exact science, but calls for common sense to evaluate the trends, identify the anomalies and arrive at an acceptable answer. Some analysts may be discouraged at the lack of transparency and be reluctant to offer a conclusion without firmer foundations, but in a political sense it seems better to provide governments with a working model upon which they can begin to plan. Such a model is illustrated in Fig. 2-6.

For the reasons explained above, it is evident that the growth of oil production over the past 150 years must give way to decline as the resources are depleted. While this can hardly be denied, a debate rages as to the date of the peak. But in fact it misses the point, especially as it is not a high or isolated peak but simply the maximum value on a gentle curve. What matters, and matters greatly, is the vision of the long decline that comes into view on the other side of it.

Fig. 2-6 illustrates a plausible model, albeit one subject to revision as new, more reliable information comes to hand. It illustrates all the categories of oil, on which some comments are offered below.

Conventional Oil

This category has supplied most to date and will dominate oil supply far into the future. It is relatively easy, cheap and fast to produce, with production costs ranging from about US$ 5/bbl in the Middle East to US$ 10-15 as a world average. The price of oil has risen three-fold in the past few years, the increase representing profiting from shortage, as the production costs have not changed materially. Some 75% of it lies in giant fields (corresponding to roughly 1% of the number of oilfields worldwide), most ofwhich were found long ago. All the significant provinces have now been identified both

The timing of the peak currently attracts much debate, but is considered less important than the vision of the long decline that comes into view on its far side.

onshore and offshore, although further small plays may yet be found in complex structural conditions, as for example in the thrust belts in front of mountain chains. The offshore too has been very thoroughly explored, having the advantage that high-quality seismic surveys may be shot relatively inexpensively. Drilling is also, somewhat surprisingly, often easier offshore than onshore, as problems of access in difficult terrain are avoided. Hopes are sometimes entertained that the former Soviet Union may have much left to find, but in reality the Soviet explorers were as efficient as their western counterparts and being free from commercial constraints could in fact plan efficient campaigns, even drilling purely to secure geological information. Indeed, the critical geochemical breakthrough that made it possible to identify the source rocks in detail owes much to Soviet scientists.

Unconventional Oil

It is convenient to include in the Heavy Oil category dense and viscous oils as well as those derived from coal and immature source rocks, as they are all characterised by a high resource base but a low extraction rate and net energy yield.

Conclusions

This Commentary concludes that the world is rapidly approaching the end of the *First Half of the Age of Oil*, during which production grew, new fields were found and developed with the help of improved geological knowledge and advances in technology. The evidence suggests that the peak of world discovery was in the 1960s, meaning that the corresponding peak of production for 'Conventional Oil' is approaching. The world started using more than it found in 1981 and that gap has widened since. Granted, certain areas (e.g. Iraq) have been closed to exploration in recent years and that increased investment will have an impact, but the overall position is dictated by the underlying constraints of nature.

The evidence suggests that the *Second Half of the Age of Oil* is dawning and that it will be characterised by the decline of oil and all that depends on it. It is stressed that oil will not finally run out for very many years, if ever, but the onset of decline is inevitable, thanks to the resource limits of nature and the immutable physics of the reservoir. The timing of the peak currently attracts much debate, but is considered less important than the vision of the long decline that comes into view on its far side.

Given the central position of oil in the modern economy, the onset of decline threatens to be a time of great economic and geopolitical tension. It certainly means that governments are starting to address the issue seriously, and the present evaluation is offered as a reasonable starting point. The risk that it will prove to have under-estimated the levels of future oil supply is certainly less than that of entering the new world unprepared and with no appropriate policies. Certainly, countries that begin to address the issue and implement the necessary changes will find themselves enjoying huge advantages over those which continue to live in the past and have blind faith in unspecified technological solutions, or the ability of an open market to deliver.

J. Peter Gerling
Federal Institute for Geosciences and Natural Resources (BGR), Germany

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DEFINITIONS

Crude oil is a naturally occurring mixture consisting predominantly of hydrocarbons that exists in liquid phase in natural underground reservoirs and is recoverable as liquids at typical atmospheric conditions of pressure and temperature. Crude oil has a viscosity no greater than 10 000 mPa.s (centipoises) at original reservoir conditions; oils of greater viscosity are included in Chapter 4 - Natural Bitumen and Extra-Heavy Oil.

Natural gas liquids (NGLs) are hydrocarbons that exist in the reservoir as constituents of natural gas but which are recovered as liquids in separators, field facilities or gas-processing plants. Natural gas liquids include (but are not limited to) ethane, propane, butanes, pentanes, natural gasoline and condensate; they may include small quantities of non-hydrocarbons.

If reserves/resources/production/consumption of NGLs exist but cannot be separately quantified, they are included (as far as possible) under crude oil.

In the tables the following definitions apply to both crude oil and natural gas liquids:

Proved amount in place is the resource remaining in known natural reservoirs that has been carefully measured and assessed as exploitable under present and expected local economic conditions with existing available technology.

Proved recoverable reserves are the quantity *within* the proved amount in place that can be recovered in the future under present and expected local economic conditions with existing available technology.

Estimated additional amount in place is the resource *additional to* the proved amount in place that is of foreseeable economic interest. Speculative amounts are not included.

Estimated additional reserves recoverable is the quantity *within* the estimated additional amount in place that geological and engineering information indicates with reasonable certainty might be recovered in the future.

R/P (reserves/production) ratio is calculated by dividing the volume of proved recoverable reserves at the end of 2005 by volumetric production in that year. The resulting figure is the time in years that the proved recoverable reserves would last if production were to continue at the 2005 level.

NOTE:

The quantifications of reserves and resources presented in the tables that follow incorporate, as far as possible, data reported by WEC Member Committees. Such data will reflect the respective Member Committees' interpretation of the above Definitions in the context of the reserves/resources information available to them, and the degree to which particular countries' terminology and statistical conventions are compatible with the WEC specifications.

TABLES

Table 2-1 Crude oil and natural gas liquids: proved recoverable reserves at end-2005

	Crude oil	NGLs	TOTAL	Crude oil	NGLs	TOTAL
		(million tonnes)			(million barrels)	
Algeria			**2 731**			**23 241**
Angola			**1 221**			**9 050**
Benin			**1**			**8**
Cameroon			**168**			**1 212**
Chad			**222**			**1 500**
Congo (Brazzaville)			**269**			**1 905**
Congo (Democratic Rep.)			**26**			**187**
Côte d'Ivoire			**64**			**471**
Egypt (Arab Rep.)	408	87	**495**	2 900	830	**3 730**
Equatorial Guinea			**245**			**1 805**
Ethiopia			**N**			**N**
Gabon			**294**			**2 146**
Ghana			**2**			**17**
Libya/GSPLAJ			**5 350**			**41 464**
Morocco			**N**			**1**
Nigeria			**4 823**			**36 220**
Senegal			**N**			**N**
South Africa			**3**			**20**
Sudan			**864**			**6 402**
Tunisia			**69**			**535**
Total Africa			**16 847**			**129 914**
Barbados			**N**			**3**
Canada	1 995	111	**2 106**	13 803	1 231	**15 034**
Cuba			**116**			**750**
Guatemala			**80**			**526**
Mexico	1 683	164	**1 847**	11 814	1 857	**13 671**
Trinidad & Tobago			**81**			**615**
United States of America	2 968	723	**3 691**	21 757	8 165	**29 922**
Total North America			**7 921**			**60 521**
Argentina			**300**			**2 196**
Bolivia			**57**			**486**
Brazil			**1 591**			**11 772**
Chile			**16**			**150**
Colombia			**197**			**1 453**
Ecuador			**719**			**5 145**
Peru	52	65	**117**	383	695	**1 078**
Surinam			**17**			**111**

Table 2-1 Crude oil and natural gas liquids: proved recoverable reserves at end-2005

	Crude oil	NGLs	TOTAL	Crude oil	NGLs	TOTAL
		(million tonnes)			(million barrels)	
Venezuela			**11 269**			**80 012**
Total South America			**14 283**			**102 403**
Azerbaijan			**950**			**7 000**
Bangladesh			**3**			**28**
Brunei			**150**			**1 120**
China			**2 212**			**16 189**
Georgia			**5**			**35**
India			**786**			**6 202**
Indonesia			**570**			**4 300**
Japan			**9**			**68**
Kazakhstan			**5 013**			**39 600**
Kyrgyzstan			**5**			**40**
Malaysia			**365**			**3 000**
Myanmar (Burma)			**7**			**50**
Pakistan			**40**			**309**
Philippines			**5**			**43**
Taiwan, China			**N**			**N**
Tajikistan			**2**			**12**
Thailand	25	26	**51**	192	261	**453**
Turkey	153	12	**165**	1 073	128	**1 201**
Turkmenistan			**74**			**546**
Uzbekistan			**70**			**594**
Vietnam			**413**			**3 100**
Total Asia			**10 895**			**83 890**
Albania			**30**			**198**
Austria			**8**			**62**
Belarus			**27**			**198**
Bulgaria			**2**			**15**
Croatia			**9**			**74**
Czech Republic			**9**			**61**
Denmark			**170**			**1 277**
France	17	N	**17**	122	5	**127**
Germany	28	N	**28**	202	2	**204**
Greece			**1**			**7**
Hungary			**20**			**167**
Italy			**106**			**744**
Lithuania			**64**			**467**
Netherlands			**11**			**88**
Norway	1 034	168	**1 202**	7 736	1 811	**9 547**

Table 2-1 Crude oil and natural gas liquids: proved recoverable reserves at end-2005

	Crude oil	NGLs	TOTAL	Crude oil	NGLs	TOTAL
	(million tonnes)			(million barrels)		
Poland	16	N	**16**	115	1	**116**
Romania	52	1	**53**	391	6	**397**
Russian Federation			**10 027**			**74 400**
Serbia			**11**			**78**
Slovakia			**1**			**9**
Slovenia			**N**			**N**
Spain			**21**			**158**
Ukraine	99	52	**151**	726	564	**1 290**
United Kingdom			**516**			**4 020**
Total Europe			**12 500**			**93 704**
Bahrain			**16**			**125**
Iran (Islamic Rep.)	13 900	3 440	**17 340**	101 190	36 300	**137 490**
Iraq			**15 478**			**115 000**
Israel			**N**			**2**
Jordan			**N**			**N**
Kuwait			**13 679**			**101 500**
Oman			**746**			**5 510**
Qatar			**1 852**			**15 207**
Saudi Arabia			**34 550**			**264 310**
Syria (Arab Rep.)			**335**			**2 459**
United Arab Emirates			**12 555**			**97 800**
Yemen			**384**			**2 970**
Total Middle East			**96 935**			**742 373**
Australia	91	134	**225**	714	1 371	**2 085**
New Zealand			**7**			**56**
Papua New Guinea			**31**			**240**
Total Oceania			**263**			**2 381**
TOTAL WORLD			**159 644**			**1 215 186**

Notes:

1. The data on the split of total oil reserves between crude and NGLs are those reported by WEC Member Committees in 2006/7. They thus constitute a sample, reflecting the information available in particular countries: they should not be considered as complete, or necessarily representative of the situation in each region. For this reason, regional and global aggregates have not been computed.
2. Where a split of reserves between crude oil and NGLs is shown, the components have been converted from barrels to tonnes (or vice versa) at specific crude oil and NGL factors for each country; where only total reserves are shown, conversions have been carried out using the crude plus NGL factor for each country.
3. Sources: WEC Member Committees, 2006/7; *Oil & Gas Journal*, 19 December, 2006; *Annual Report 2005*, OAPEC; *Annual Statistical Bulletin* 2005, OPEC; *World Oil*, September 2006; *BP Statistical Review of World Energy 2006*; various national sources

Table 2-2i Crude oil and natural gas liquids: resources at end-2005 (million tonnes)

	Crude oil			Natural gas liquids		
	Proved amount in place	Estimated additional		Proved amount in place	Estimated additional	
		Amount in place	Reserves recoverable		Amount in place	Reserves recoverable
Africa						
Algeria	9 247					
Cameroon	183					
Côte d'Ivoire	79					
South Africa	7	14	6			
North America						
Canada		790	621-683		160	126-138
Mexico	2 714	2 439	1 659	265	158	107
South America						
Brazil			599			
Peru			59			28
Asia						
India	1 652					
Thailand		25	15		50	33
Turkey	957					
Europe						
Austria	11					
Croatia	10					
Czech Republic	13		11			
Denmark		123	45			
France	341			11		
Germany			19			
Hungary	221	33-195	10-58			
Italy		57-386				
Poland	17	3		1	N	
Romania	1 947	124	62	11	2	N
Ukraine	115	37	20	64	18	9
United Kingdom			751			

Table 2-2i Crude oil and natural gas liquids: resources at end-2005 (million tonnes)

	Crude oil			Natural gas liquids		
	Proved amount in place	Estimated additional		Proved amount in place	Estimated additional	
		Amount in place	Reserves recoverable		Amount in place	Reserves recoverable
Middle East						
Israel	1					
Syria (Arab Rep.)			5			
Oceania						
New Zealand	50	18				

Notes:

1. The data on resources are those reported by WEC Member Committees. They thus constitute a sample, reflecting the information available in particular countries: they should not be considered as complete, or necessarily representative of the situation in each region. For this reason, regional and global aggregates have not been computed.
2. Some of the figures above have been converted from data reported in volumetric terms (e.g. barrels), using specific crude oil and NGL factors for each country. The results have generally been left unrounded, although their apparent precision should be disregarded.
3. Sources: WEC Member Committees, 2006/7

Table 2-2ii Crude oil and natural gas liquids: resources at end-2005 (million barrels)

	Crude oil			Natural gas liquids		
	Proved amount in place	Estimated additional		Proved amount in place	Estimated additional	
		Amount in place	Reserves recoverable		Amount in place	Reserves recoverable
Africa						
Algeria	78 692					
Cameroon	1 322					
Côte d'Ivoire	581					
South Africa	51	107	43			
North America						
Canada		5 774	4 541-4 994		1 777	1 398-1 537
Mexico	19 054	17 123	11 644	2 995	1 784	1 213

Table 2-2ii Crude oil and natural gas liquids: resources at end-2005 (million barrels)

	Crude oil			Natural gas liquids		
	Proved amount in place	Estimated additional		Proved amount in place	Estimated additional	
		Amount in place	Reserves recoverable		Amount in place	Reserves recoverable
South America						
Brazil			4 359			
Peru			438			294
Asia						
India	12 440					
Thailand		195	119		451	293
Turkey	6 709					
Europe						
Austria	81					
Croatia	74					
Czech Republic	88		75			
Denmark		918	340			
France	2 513			111		
Germany			137			
Hungary	1 658	248-1 463	75-435			
Italy		400-2 700				
Poland	128	21		14	2	
Romania	14 621	929	465	117	21	4
Ukraine	841	273	147	696	195	92
United Kingdom			5 850			
Middle East						
Israel	4					
Syria (Arab Rep.)			38			
Oceania						
New Zealand	407	147				

Notes:

1. The data on resources are those reported by WEC Member Committees. They thus constitute a sample, reflecting the information available in particular countries: they should not be considered as complete, or necessarily representative of the situation in each region. For this reason, regional and global aggregates have not been computed.
2. Some of the figures above have been converted from data reported in tonnes, using specific crude oil and NGL factors for each country. The results have generally been left unrounded, although their apparent precision should be disregarded.
3. Sources: WEC Member Committees, 2006/7

Table 2-3 Crude oil and natural gas liquids: 2005 production

	Crude oil	NGLs	Total	Crude oil	NGLs	Total	
	(million tonnes)			(thousand barrels per day)			R/P ratio
Algeria	63.1	23.4	86.5	1 373	642	2 015	31.6
Angola	62.3		62.3	1 265		1 265	19.6
Cameroon	4.3		4.3	84		84	39.5
Chad	9.3		9.3	173		173	23.8
Congo (Brazzaville)	13.1		13.1	253		253	20.6
Congo (Democratic Rep.)	1.0		1.0	20		20	25.6
Côte d'Ivoire	2.0		2.0	40		40	32.3
Egypt (Arab Rep.)	28.5	5.4	33.9	554	142	696	14.7
Equatorial Guinea	17.6		17.6	355		355	13.9
Gabon	11.7		11.7	234		234	25.1
Ghana	0.3		0.3	6		6	7.8
Libya/GSPLAJ	77.9	2.2	80.1	1 640	62	1 702	66.7
Morocco	N		N	N		N	11.0
Nigeria	117.5	7.9	125.4	2 386	194	2 580	38.5
Senegal							
South Africa	0.9	0.2	1.1	20	5	25	2.8
Sudan	17.5		17.5	355		355	49.4
Tunisia	3.5	0.1	3.6	73	4	77	19.0
Total Africa	**430.5**	**39.2**	**469.7**	**8 831**	**1 049**	**9 880**	**36.0**
Barbados	0.1		0.1	1		1	8.2
Canada	122.1	21.1	143.2	2 355	642	2 997	13.7
Cuba	3.0		3.0	53		53	38.8
Guatemala	1.0		1.0	18		18	78.2
Mexico	173.3	13.8	187.1	3 333	426	3 759	10.0
Trinidad & Tobago	6.6	1.7	8.3	126	45	171	9.9
United States of America	257.8	55.5	313.3	5 178	1 717	6 895	11.9
Total North America	**563.9**	**92.1**	**656.0**	**11 064**	**2 830**	**13 894**	**11.9**
Argentina	35.6	2.9	38.5	705	91	796	7.6
Bolivia	1.9	0.2	2.1	42	7	49	27.2
Brazil	82.1	2.6	84.7	1 637	79	1 716	18.8
Chile	0.2	0.2	0.4	3	5	8	48.9
Colombia	26.4	0.6	27.0	526	20	546	7.3
Ecuador	27.3	0.3	27.6	532	9	541	26.1
Peru	3.7	1.2	4.9	75	36	111	26.5
Surinam	0.7		0.7	12		12	25.3
Venezuela	146.8	7.9	154.7	2 792	215	3 007	72.9
Total South America	**324.7**	**15.9**	**340.6**	**6 324**	**462**	**6 786**	**41.3**

Table 2-3 Crude oil and natural gas liquids: 2005 production

	Crude oil	NGLs	Total	Crude oil	NGLs	Total	
	(million tonnes)			(thousand barrels per day)			R/P ratio
Azerbaijan	22.0	0.4	22.4	440	12	452	42.4
Bangladesh		0.1	0.1		2	2	35.0
Brunei	9.6	0.5	10.1	192	14	206	14.9
China	180.8		180.8	3 627		3 627	12.2
Georgia	0.1	N	0.1	1	N	1	68.6
India	32.5	3.8	36.3	670	114	784	21.7
Indonesia	47.3	6.7	54.0	937	178	1 115	10.6
Japan	0.8		0.8	16		16	11.6
Kazakhstan	50.9	11.7	62.6	1 018	338	1 356	80.1
Kyrgyzstan	0.1	N	0.1	2	N	2	71.2
Malaysia	27.3	9.5	36.8	571	256	827	9.9
Myanmar (Burma)	1.1	N	1.1	22	N	22	6.2
Pakistan	3.2	0.2	3.4	66	6	72	11.8
Philippines	N	0.6	0.6	1	15	16	7.4
Taiwan, China	N		N	1		1	
Tajikistan	N	N	N	N	N	N	82.2
Thailand	5.4	5.4	10.8	114	150	264	6.8
Turkey	1.9		1.9	37		37	89.3
Turkmenistan	9.3	0.2	9.5	186	6	192	7.8
Uzbekistan	3.5	2.0	5.5	69	58	127	12.8
Vietnam	18.5	0.6	19.1	375	17	392	21.7
Total Asia	**414.3**	**41.7**	**456.0**	**8 345**	**1 166**	**9 511**	**24.2**
Albania	0.4		0.4	7		7	75.0
Austria	0.8	0.1	0.9	16	2	18	9.1
Belarus	1.8		1.8	36		36	15.2
Bulgaria	N		N	1		1	68.2
Croatia	0.9		0.9	21		21	9.6
Czech Republic	0.3		0.3	6		6	28.7
Denmark	18.4		18.4	377		377	9.3
France	1.1	0.1	1.2	22	3	25	14.1
Germany	3.5	0.1	3.6	70	3	73	7.7
Greece	0.1	N	0.1	2	N	2	9.3
Hungary	1.1	0.2	1.3	23	6	29	16.0
Italy	6.1	N	6.1	117	1	118	17.3
Lithuania	0.2		0.2	4		4	>100
Netherlands	2.5		2.5	53		53	4.5
Norway	124.6	13.6	138.2	2 553	416	2 969	8.8
Poland	0.8	N	0.8	17	N	17	18.3

Table 2-3 Crude oil and natural gas liquids: 2005 production

	Crude oil	NGLs	Total	Crude oil	NGLs	Total	
	(million tonnes)			(thousand barrels per day)			R/P ratio
Romania	5.2	0.1	5.3	107	4	111	9.8
Russian Federation	452.4	17.8	470.2	9 048	508	9 556	21.3
Serbia	0.6	0.2	0.8	13	6	19	11.3
Slovakia	N	N	N	1	N	1	42.8
Slovenia	N	N	N	N	1	1	
Spain	0.2		0.2	3		3	>100
Ukraine	3.1	1.1	4.2	62	34	96	37.0
United Kingdom	77.2	7.5	84.7	1 586	223	1 809	6.1
Total Europe	**701.3**	**40.8**	**742.1**	**14 145**	**1 207**	**15 352**	**16.7**
Bahrain	1.9	0.3	2.2	38	10	48	7.1
Iran (Islamic Rep.)	196.8	8.1	204.9	3 925	235	4 160	90.5
Iraq	89.2	0.3	89.5	1 810	10	1 820	>100
Israel	N		N	N		N	86.4
Jordan	N		N	N		N	
Kuwait	124.9	5.2	130.1	2 485	158	2 643	>100
Oman	38.4	0.1	38.5	775	5	780	19.4
Qatar	36.6	9.2	45.8	764	262	1 026	40.6
Saudi Arabia	481.1	45.1	526.2	9 596	1 439	11 035	65.6
Syria (Arab Rep.)	20.6		20.6	414		414	16.3
United Arab Emirates	118.4	10.6	129.0	2 444	307	2 751	97.4
Yemen	19.1	0.7	19.8	400	22	422	19.3
Total Middle East	**1 127.0**	**79.6**	**1 206.6**	**22 651**	**2 448**	**25 099**	**81.0**
Australia	14.8	8.5	23.3	319	235	554	10.3
New Zealand	0.9	0.2	1.1	19	5	24	6.2
Papua New Guinea	2.2		2.2	47		47	14.0
Total Oceania	**17.9**	**8.7**	**26.6**	**385**	**240**	**625**	**10.4**
TOTAL WORLD	**3 579.6**	**318.0**	**3 897.6**	**71 745**	**9 402**	**81 147**	**41.0**

Notes:

1. Sources: WEC Member Committees, 2006/7; *BP Statistical Review of World Energy 2006; Oil & Gas Journal*, other international and national sources
2. Conversions from barrels to tonnes (or vice versa) have been carried out using specific crude oil and NGL factors for each country.

Table 2-4 Crude oil and natural gas liquids: 2005 consumption

	Crude oil	NGLs	Total	Crude oil	NGLs	Total
	(million tonnes)			(thousand barrels per day)		
Algeria	17.7		17.7	355		355
Angola	2.0		2.0	40		40
Cameroon	2.0		2.0	40		40
Congo (Brazzaville)	0.6		0.6	12		12
Congo (Democratic Rep.)	N		N	N		N
Côte d'Ivoire	4.0		4.0	80		80
Egypt (Arab Rep.)	29.0	3.0	32.0	582	85	667
Gabon	0.7		0.7	14		14
Ghana	1.9		1.9	38		38
Kenya	1.7		1.7	34		34
Libya/GSPLAJ	17.0		17.0	340		340
Madagascar	0.5		0.5	10		10
Morocco	6.5		6.5	130		130
Nigeria	5.5		5.5	110		110
Senegal	1.2		1.2	24		24
South Africa	20.5		20.5	415		415
Sudan	4.0		4.0	80		80
Tunisia	1.8		1.8	36		36
Zambia	0.6		0.6	12		12
Total Africa	**117.2**	**3.0**	**120.2**	**2 352**	**85**	**2 437**
Aruba	0.5		0.5	10		10
Canada	88.0	3.0	91.0	1 765	85	1 850
Costa Rica	0.5		0.5	10		10
Cuba	5.0		5.0	100		100
Dominican Republic	2.2		2.2	44		44
El Salvador	1.0		1.0	20		20
Jamaica	0.8		0.8	16		16
Martinique	0.6		0.6	12		12
Mexico	64.8	15.3	80.1	1 301	436	1 737
Netherlands Antilles	11.0		11.0	220		220
Nicaragua	0.9		0.9	18		18
Puerto Rico	2.5		2.5	50		50
Trinidad & Tobago	8.2		8.2	165		165
United States of America	757.9	15.5	773.4	15 220	441	15 661
US Virgin Islands	22.5		22.5	450		450
Total North America	**966.4**	**33.8**	**1 000.2**	**19 401**	**962**	**20 363**
Argentina	26.6		26.6	534		534
Bolivia	1.8		1.8	36		36
Brazil	84.8	2.8	87.6	1 703	79	1 782

Table 2-4 Crude oil and natural gas liquids: 2005 consumption

	Crude oil	NGLs	Total	Crude oil	NGLs	Total
		(million tonnes)			(thousand barrels per day)	
Chile	10.5	N	10.5	210	N	210
Colombia	14.9		14.9	299		299
Ecuador	7.7		7.7	155		155
Paraguay	0.1		0.1	2		2
Peru	8.0	1.3	9.3	160	37	197
Surinam	0.5		0.5	10		10
Uruguay	2.0		2.0	40		40
Venezuela	57.8		57.8	1 160		1 160
Total South America	**214.7**	**4.1**	**218.8**	**4 309**	**116**	**4 425**
Azerbaijan	6.3	0.4	6.7	127	11	138
Bangladesh	1.3	0.1	1.4	26	3	29
Brunei	0.3	0.4	0.7	6	11	17
China	294.6		294.6	5 916		5 916
Georgia	0.1		0.1	1		1
India	127.1	2.1	129.2	2 552	60	2 612
Indonesia	50.0	0.2	50.2	1 005	5	1 010
Japan	201.3	5.3	206.6	4 043	151	4 194
Kazakhstan	12.5	0.8	13.3	250	23	273
Korea (Democratic People's Rep.)	0.6		0.6	12		12
Korea (Republic)	116.2		116.2	2 335		2 335
Kyrgyzstan	0.1		0.1	2		2
Malaysia	25.0		25.0	502		502
Myanmar (Burma)	1.0		1.0	20		20
Pakistan	11.5		11.5	230		230
Philippines	11.0		11.0	220		220
Singapore	58.5		58.5	1 176		1 176
Sri Lanka	2.0		2.0	40		40
Taiwan, China	51.9	0.1	52.0	1 042	3	1 045
Tajikistan	N		N	N		N
Thailand	45.4	0.4	45.8	912	11	923
Turkey	29.3		29.3	588		588
Turkmenistan	6.5	0.7	7.2	130	20	150
Uzbekistan	4.0	2.0	6.0	80	57	137
Vietnam						
Total Asia	**1 056.5**	**12.5**	**1 069.0**	**21 215**	**355**	**21 570**
Albania	0.4		0.4	8		8
Austria	8.8	0.1	8.9	177	3	180
Belarus	20.0		20.0	402		402
Belgium	31.4		31.4	631		631

Table 2-4 Crude oil and natural gas liquids: 2005 consumption

	Crude oil	NGLs	Total	Crude oil	NGLs	Total
	(million tonnes)			(thousand barrels per day)		
Bulgaria	5.5		5.5	110		110
Croatia	4.5		4.5	91		91
Czech Republic	7.7		7.7	156		156
Denmark	7.6		7.6	153		153
Finland	11.1	1.1	12.2	223	31	254
FYR Macedonia	0.8		0.8	16		16
France	85.3		85.3	1 712		1 712
Germany	115.0	0.1	115.1	2 309	3	2 312
Greece	18.9	N	18.9	380	N	380
Hungary	6.6	0.2	6.8	133	6	139
Ireland	3.1		3.1	62		62
Italy	86.9		86.9	1 745		1 745
Latvia	N		N	N		N
Lithuania	9.2		9.2	185		185
Netherlands	48.8	12.2	61.0	980	348	1 328
Norway	16.1		16.1	323		323
Poland	18.3	N	18.3	367	N	367
Portugal	13.2		13.2	265		265
Romania	13.9		13.9	279		279
Russian Federation	190.0	10.0	200.0	3 815	285	4 100
Serbia	3.7	0.2	3.9	73	6	79
Slovakia	5.4		5.4	108		108
Spain	60.3		60.3	1 210		1 210
Sweden	21.0		21.0	422		422
Switzerland	5.4		5.4	108		108
Ukraine	25.0	1.5	26.5	502	43	545
United Kingdom	82.2	1.0	83.2	1 651	28	1 679
Total Europe	**926.1**	**26.4**	**952.5**	**18 596**	**753**	**19 349**
Bahrain	12.7		12.7	255		255
Iran (Islamic Rep.)	73.0	7.0	80.0	1 465	200	1 665
Iraq	23.0		23.0	465		465
Israel	11.0		11.0	221		221
Jordan	4.6		4.6	92		92
Kuwait	45.0		45.0	904		904
Oman	4.3		4.3	86		86
Qatar	3.5	1.7	5.2	70	48	118
Saudi Arabia	100.0	12.0	112.0	2 008	342	2 350
Syria (Arab Rep.)	12.0		12.0	241		241
United Arab Emirates	18.5		18.5	375		375
Yemen	3.5		3.5	70		70

Table 2-4 Crude oil and natural gas liquids: 2005 consumption

	Crude oil	NGLs	Total	Crude oil	NGLs	Total
		(million tonnes)			(thousand barrels per day)	
Total Middle East	**311.1**	**20.7**	**331.8**	**6 252**	**590**	**6 842**
Australia	27.9		27.9	560		560
New Zealand	5.1		5.1	103		103
Total Oceania	**33.0**		**33.0**	**663**		**663**
TOTAL WORLD	**3 625.0**	**100.5**	**3 725.5**	**72 788**	**2 861**	**75 649**

Notes:

1. The data refer to consumption of indigenous and imported crude oil and NGLs, comprising refinery throughput plus direct use of crude oil/ngls as fuel.
2. It is often not possible to isolate consumption of NGLs; if details are unavailable they are included with crude oil. This situation makes it impossible to calculate accurate conversions of oil consumption from tonnes to barrels in all cases.
3. Sources: WEC Member Committees 2006/7; *Quarterly Statistics*, *Fourth quarter, 2006*, IEA; other international and national sources; estimates by the Editors

COUNTRY NOTES

The following Country Notes on Crude Oil and Natural Gas Liquids provide a brief account of countries with significant oil reserves/production. They have been compiled by the Editors, drawing upon a wide variety of material, including information received from WEC Member Committees, national and international publications.

The principal international published sources consulted were:

- *Annual Statistical Bulletin 2005*, 2006; OPEC;
- *BP Statistical Review of World Energy*, *2006;*
- *Energy Balances of OECD Countries 2003-2004*; 2006; International Energy Agency;
- *Energy Balances of Non-OECD Countries 2003-2004*; 2006; International Energy Agency;
- *Energy Statistics of OECD Countries 2003-2004*; 2006; International Energy Agency;
- *Energy Statistics of Non-OECD Countries 2003-2004*; 2006; International Energy Agency;
- *Oil & Gas Journal*, various issues; PennWell Publishing Co.;
- *Our Industry Petroleum*; 1977; The British Petroleum Company Ltd.;
- *Quarterly Statistics Fourth Quarter 2006*; 2007; International Energy Agency
- *Secretary General's 32nd Annual Report, A.H. 1425-1426/A.D. 2005*; 2006, OAPEC;
- *World Oil*, September 2006; Gulf Publishing Company.

Brief salient data are shown for each country, including the year of first commercial production (where it can be ascertained).

Please note that Reserves/Production (R/P) ratios have been calculated on volumetric data (barrels): owing to differential conversion factors, R/P ratios based on tonnes would not generally equate to those based on volumes.

Algeria

Proved recoverable reserves (crude oil and NGLs, million tonnes)	2 731
Production (crude oil and NGLs, million tonnes, 2005)	86.5
R/P ratio (years)	31.6
Year of first commercial production	1950

Indigenous oil reserves are the third largest in the African region, after Libya and Nigeria. The principal oil provinces are located in the central and south-eastern parts of the country, with the largest oil field being Hassi Messaoud, which was discovered in 1956. Substantial volumes of

NGLs (condensate and LPG) are produced at Hassi R'mel and other gas fields. Algerian crudes are of high quality, with a low sulphur content.

For the present *Survey*, the levels adopted are those advised by the Algerian WEC Member Committee: 12 511 million cubic metres (78.7 billion barrels) of oil in place and 3 695 million cubic metres (23.2 billion barrels) of proved recoverable oil reserves.

Algeria has been a member of OPEC since 1969 and is also a member of OAPEC. It exported about 75% of its output of crude oil (including condensate) in 2005, mainly to Western Europe and North America.

Angola

Proved recoverable reserves (crude oil and NGLs, million tonnes)	1 221
Production (crude oil and NGLs, million tonnes, 2005)	62.3
R/P ratio (years)	19.6
Year of first commercial production	1956

Proved reserves of oil (9 050 million barrels, as quoted by *World Oil*) are the second largest in sub-Saharan Africa. *Oil & Gas Journal* has recently raised its estimate (to 8 billion barrels at end-2006); the other standard published sources all quote levels close to that of *World Oil*.

The early discoveries (from 1955 onwards) were made on land, but the greater part of Angola's oil resources lies in the coastal waters of its enclave of Cabinda and off the north-western mainland. Major discoveries have since been made in deep water locations. Offshore exploration and production activities largely escaped disruption during the long civil war, and output has risen sharply since 2001. By far the greater part of the crude produced is exported. Angola became a member of OPEC with effect from 1 January 2007.

Argentina

Proved recoverable reserves (crude oil and NGLs, million tonnes)	300
Production (crude oil and NGLs, million tonnes, 2005)	38.5
R/P ratio (years)	7.6
Year of first commercial production	1907

In terms of oil resources, Argentina lies in the middle ranks of South American countries, with a level of reserves which exceeds those of Colombia and Peru. The main oil-producing areas are the west-central areas of Neuquén and Cuyo-Mendoza, the Noroeste area near Bolivia in the north, the southern province of Chubut and the Austral area in the far south (including Argentina's portion of Tierra del Fuego). Offshore fields have been discovered in the San Jorge basin off Chubut province and near Tierra del Fuego.

Proved recoverable oil reserves at end-2005 are reported by the Secretaría de Energía as 349.1 million m^3 (2 196 million barrels), a reduction of 11.4% on the end-2004 figure. Published assessments of proved reserves tend to come out slightly higher than the official level. The estimated level of additional recoverable oil ('probable reserves') is given by the Secretaría as 153.3 million m^3 (964 million barrels).

Oil output rose strongly during most of the 1990s, but a decline set in at the end of the decade: production of crude oil and condensate in 2005 was down to 705 000 b/d plus about 90 000 b/d of gas plant NGLs. The Golfo San Jorge and Neuquina basins account for the bulk of oil production. A sizeable proportion of Argentinian crude is exported (25% in 2004).

Australia

Proved recoverable reserves (crude oil and NGLs, million tonnes)	225
Production (crude oil and NGLs, million tonnes, 2005)	23.3
R/P ratio (years)	10.3
Year of first commercial production	1964

Although drilling for oil took place as long ago as 1892, it was not until well after World War II that Australia achieved oil-producer status. Since then, numerous oil fields have been discovered, notably in the following areas: Gippsland Basin (Bass Strait), off Victoria; Cooper Basin, South Australia; Eromanga and Surat Basins, Queensland; Carnarvon Basin (North-west Shelf) off Western Australia; Bonaparte Basin in the Timor Sea.

According to Geoscience Australia data as at 1 January 2005, 'remaining commercial reserves' were 113.6 gigalitres of crude oil and 100.8 gigalitres of condensate. With the inclusion of 117.1 gigalitres of naturally-occurring LPG, total proved recoverable oil reserves amounted to 331.5 gigalitres, equivalent to 2 085 million barrels or almost 225 million tonnes. Commercially published estimates of Australian oil reserves differ considerably from Geoscience Australia's level: *Oil & Gas Journal* quotes 1 437 million barrels and *World Oil* 4 015.

The estimated additional reserves recoverable, on the basis of Geoscience Australia's estimates of reserves that have not yet been declared commercially viable (non-commercial reserves), are as follows (in gigalitres): crude oil 124.2; condensate 314.9; naturally-occurring LPG 174.8, giving a total crude plus NGLs of 613.9 gigalitres or 3 861 million barrels.

Production of oil (including condensate and other NGLs) has fluctuated in recent years: in 2005 it averaged 554 000 b/d, of which crude oil accounted for 58%, condensate 22% and LPG/ethane for 20%. About 50% of Australia's total oil output in 2005 was exported, mostly to Japan and other Asian destinations, the USA and New Zealand.

Azerbaijan

Proved recoverable reserves (crude oil and NGLs, million tonnes)	950
Production (crude oil and NGLs, million tonnes, 2005)	22.4
R/P ratio (years)	42.4
Year of first commercial production	1873

This is one of the world's oldest oil-producing areas, large-scale commercial production having started in the 1870s. During World War II the republic was the USSR's major source of crude, but then decreased in importance as the emphasis moved to Siberia. Azerbaijan's proved recoverable reserves (as reported by *Oil & Gas Journal*, OAPEC and BP) stand at 7 billion barrels, unchanged from the level quoted in the 2004 *Survey*.

The development of Azerbaijan's offshore oil resources in the Caspian Sea, currently under way, is re-establishing the republic as a major oil producer and exporter. With new Caspian fields coming into production, oil output has risen year by year since 1998. The bulk of Azerbaijan's production is obtained offshore.

Brazil

Proved recoverable reserves (crude oil and NGLs, million tonnes)	1 591
Production (crude oil and NGLs, million tonnes, 2005)	84.7
R/P ratio (years)	18.8
Year of first commercial production	1940

Brazil's proved reserves feature significantly within the Western Hemisphere - not quite in the same league as the four largest producers (Venezuela, USA, Canada and Mexico), but greater than the sum of those in all other countries in South America apart from Venezuela. Most of the reserves located up until the mid-1970s were in the north-east and central regions, remote from the main centres of oil demand in the south and south-east. Discoveries in offshore areas, in particular the Campos Basin, transformed the reserves picture.

The level of proved recoverable reserves of oil (1 871.6 million m^3, equal to 11 772 million barrels) reported by the Brazilian WEC Member Committee corresponds with the figure for ‘measured/indicated/inventoried reserves’ published by the Ministério de Minas e Energia in its *Balanço Energético Nacional 2006* (BEN), and is 20% higher than that advised for the 2004 Survey. The standard published assessments of proved reserves are currently all in line with the reported level. Of the reserves reported by the Member Committee, 92.5% is located offshore.

Additional recoverable reserves, based on ‘inferred/estimated reserves’ in the BEN, are reported as 693.1 million m^3 (equivalent to 4 359 million barrels or 589 million tonnes).

Oil production has followed a strongly upward trend for more than 10 years, reaching an average of over 1.7 million b/d in 2005, with 83% of Brazil's output being processed in domestic refineries.

Brunei

Proved recoverable reserves (crude oil and NGLs, million tonnes)	150
Production (crude oil and NGLs, million tonnes, 2005)	10.1
R/P ratio (years)	14.9
Year of first commercial production	1929

Although the earliest discoveries (Seria and Rasau fields) were made on land, virtually all subsequent oil fields have been found in offshore waters. Proved recoverable reserves reflect the level of 1 120 million barrels quoted in the *OPEC Annual Statistical Bulletin 2005*. There is now consensus among the main published sources that total oil reserves are of this order, *Oil & Gas Journal* having reduced its evaluation to 1 100 million (as at end-2006) from the 1 350 million at which it had stood since 1990.

There were nine offshore fields in production in 2005, together with two onshore fields: total output (including 14 000 b/d of natural gasoline) was 206 000 b/d, in line with the average for the previous five years. More than 90% of Brunei's oil output is exported, mostly to Japan, Thailand, South Korea and Singapore.

Canada

Proved recoverable reserves (crude oil, NGLs and oil sands, million tonnes)	2 106
Production (crude oil, NGLs and oil sands, million tonnes, 2005)	143.2
R/P ratio (years)	13.7
Year of first commercial production	1862

The levels of proved recoverable reserves adopted for the present *Survey* correspond with the 'Remaining Reserves as at 2005-12-31' reported by the Reserves Committee of the Canadian Association of Petroleum Producers (CAPP) in the *CAPP Statistical Handbook* (November 2006). Reserves comprise 828 million m^3 of conventional crude oil, 196 million m^3 of natural gas liquids (71 pentanes plus and 125 ethane/propane/butane), and 1 366 million m^3 of oil sands and natural bitumen (973 'developed mining - upgraded and bitumen' and 393 'developed in-situ – bitumen').

Two provinces (Alberta and Saskatchewan) account for the bulk of western Canada's conventional crude oil reserves. The East Coast Offshore reserves hold 273 million m^3 of crude oil. Most of the NGL reserves are located in Alberta.

Based on assessments by the National Energy Board (NEB), further quantities of crude oil, up to 794 million m^3 and 244 million m^3 of NGLs, are considered to be potentially recoverable. For northern Canada, probabilistic estimates of recoverable crude oil were made by the NEB. At the mean probability, 173 million m^3 of crude oil is expected to be recoverable. Apart from the Norman Wells field in the Northwest Territories, there are no other crude oil developments.

The quantities of oil sands/bitumen included in Canada's proved reserves quoted above correspond with 'remaining established reserves' of 'developed non-conventional oil' at end-2005 published by CAPP in its *Statistical Handbook* and included by the Reserves Committee of CAPP in its 2005 Report.

'Established reserves' are defined by CAPP as 'those reserves recoverable under current technology and present and anticipated economic conditions, specifically proved by drilling, testing or production, plus that judgement portion of contiguous recoverable reserves that are interpreted to exist, from geological, geophysical or similar information, with reasonable certainty'. 'Developed synthetic crude oil and bitumen reserves' are defined by CAPP as 'those recoverable from developed experimental/demonstration and commercial projects'.

While there is no consensus as to the precise level to include, it is standard practice to include Canadian oil sands/bitumen in compilations of proved oil reserves. The approach adopted for the present *Survey* reflects the practice of the CAPP Reserves Committee and is also broadly similar to that used by BP in its *Statistical Review of World Energy, 2006* and by *World Oil* in its annual compilation of Estimated Proven World Reserves. BP states that it includes 'an official estimate of Canadian oil sands under active development', whilst *World Oil* describes its data for Canada as comprising 'reserves that are recoverable with current technology and under present economic conditions'. These descriptions accord closely with the WEC definition of proved recoverable reserves.

In 2005, output of conventional crude was 217 000 m^3/d, that of NGLs 102 000 m^3/d and production from oil sands 158 000 m^3/d. Conventional light crude oil has been declining in production for a number of years and conventional heavy crude oil is expected to show a production decline after 2007.

Canada is the world leader in the production of oil from deposits of oil sands. The estimated ultimately recoverable resource from this 'newly conventional' supply is 55 billion cubic metres, second only to Saudi Arabia - see the chapter on Natural Bitumen.

Chad

Proved recoverable reserves (crude oil and NGLs, million tonnes)	222
Production (crude oil and NGLs, million tonnes, 2005)	9.3
R/P ratio (years)	23.8
Year of first commercial production	2003

The West African republic of Chad joined the ranks of the world's crude oil producers in July 2003, after the construction of a 1 070 km export pipeline from the oil fields in the Doba Basin of southern Chad through Cameroon to a new terminal at Kribi. The development of the Doba Basin fields (Bolobo, Komé and Miandoum) and the pipeline is handled by a consortium consisting of ExxonMobil (40%), Petronas, the Malaysian state oil company (35%), and ChevronTexaco (25%).

In 2002 recoverable reserves were stated by Esso Exploration & Production Chad, Inc. to be 'slightly more than 900 million barrels'. For the purpose of the present *Survey*, *Oil & Gas Journal*'s estimate of 1 500 million barrels as at end-2005 has been adopted for proved reserves, as further fields have been developed and are being brought into production.

The oil offered for export is called Doba Blend. Initial supplies were typically of 24.8° API and 0.14% sulphur; after March 2004, when the

Komé field came on-stream, the blend's characteristics moved to a lower gravity (20.5° API) and a slightly higher sulphur content (0.16%).

China

Proved recoverable reserves (crude oil and NGLs, million tonnes)	2 212
Production (crude oil and NGLs, million tonnes, 2005)	180.8
R/P ratio (years)	12.2
Year of first commercial production	1939

The first significant oil find was the Lachunmia field in the north-central province of Gansu, which was discovered in 1939. An extensive exploration programme, aimed at self-sufficiency in oil, was launched in the 1950s; two major field complexes were discovered: Daqing (1959) in the north-eastern province of Heilongjiang and Shengli (1961) near the Bo Hai gulf.

As the Chinese WEC Member Committee was unable to contribute any data for the present *Survey*, oil reserves are based upon published material. The major sources appear to be approaching a degree of consensus: *World Oil*, OPEC and BP all quote a level in the vicinity of 16 billion barrels, whilst *Oil & Gas Journal* has reduced its estimate from 18.25 billion at end-2005 to 16 billion at end-2006. OAPEC quotes 18.25, possibly echoing OGJ’s earlier figure.

China's oil reserves are by far the largest of any country in Asia: oil output is on a commensurate scale, with the 2005 level accounting for about 40% of the regional tonnage. China exported 8.1 million tonnes of its crude oil in 2005.

Colombia

Proved recoverable reserves (crude oil and NGLs, million tonnes)	197
Production (crude oil and NGLs, million tonnes, 2005)	27.0
R/P ratio (years)	7.3
Year of first commercial production	1921

Initially, oil discoveries were made principally in the valley of the Magdalena. Subsequently, other fields were discovered in the north of the country (from the early 1930s), and in 1959 oil was found in the Putamayo area in southern Colombia, near the border with Ecuador. More recently, major discoveries have included the Caño Limón field near the Venezuelan frontier and the Cusiana and Cupiagua fields in the Llanos Basin to the east of the Andes. However, the remaining proved reserves have been shrinking since 1992, and are now at a very low level in relation to production (R/P ratio of only 7.3), on the basis of data published by the Unidad de Planeación Minero Energético (UPME) of the Ministerio de Minas y Energía, in its *Boletín Estadístico 1999-2005*. UPME remarks that oil reserves decreased at an average rate of 7.4% per annum between 1998 and 2005, owing largely to declines in the Caño Limón and Cusiana fields. However, it has high hopes of finding further reserves, with the promotion of new areas on the part of the state company Ecopetrol and the Agencia Nacional de Hidrocarburos.

Colombia's oil production grew strongly between 1994 and 1999, increasing by about 80% over the period: 2000, however, displayed a sharp contraction, and output has continued to fall year by year.

Congo (Brazzaville)

Proved recoverable reserves (crude oil and NGLs, million tonnes)	269
Production (crude oil and NGLs, million tonnes, 2005)	13.1
R/P ratio (years)	20.6
Year of first commercial production	1957

The proved recoverable reserves shown above reflect the end-2005 level of ‘proven crude reserves’ (1 905 million barrels) published by *World Oil* in September 2006. By way of contrast, *Oil & Gas Journal* had reported a constant level of 1 506 million barrels of proved oil reserves for over ten years up to and including end-2005, but its most recent assessment gives a figure of 1 600 million for end-2006.

After becoming a significant oil producer in the mid-1970s, Congo (Brazzaville) is now the fourth largest in sub-Saharan Africa. Most of the fields in current production are located in coastal waters. The average quality of oil output has improved over the years, aided by the coming on-stream of Elf's deep-water Nkossa field. The bulk of oil production is exported.

Denmark

Proved recoverable reserves (crude oil and NGLs, million tonnes)	170
Production (crude oil and NGLs, million tonnes, 2005)	18.4
R/P ratio (years)	9.3
Year of first commercial production	1972

Denmark's proved recoverable reserves are the fourth largest in Europe (excluding the Russian Federation). The Danish Energy Authority (DEA) does not employ the terms ‘proved’ and ‘additional’ reserves, but uses the categories ‘ongoing’, ‘approved’, ‘planned’ and ‘possible’ recovery. The figure for proved reserves (203 million m^3 or 1 277 million barrels) reported by the DEA to the Danish WEC Member Committee has been calculated as the sum of ‘ongoing’ and ‘approved’ reserves, while the figure for additional reserves has been calculated as the sum of 7 million m^3 ‘planned’ reserves and 47 million m^3 ‘possible’ reserves. The reserve numbers are the expected values in each category.

All the oil fields discovered so far are located in the North Sea. Out of 23 fields or areas with reserves in the ongoing/approved category, four (Dan, Gorm, Halfdan and South Arne) account for 83% of the total volume.

Assuming an average future recovery factor of 24%, the proved amount in place corresponding to the ongoing/approved reserves of 203 million m^3 is 846 million m^3 (approximately 5.3 billion barrels); beyond these quantities is an estimated additional amount in place of 146 million m^3 (918 million barrels), of which 54 million m^3 (340 million barrels) is deemed to be recoverable.

The principal fields in production in 2005 were Halfdan, Dan, South Arne, Gorm and Skjold, which together accounted for 80% of national oil output. About three-quarters of Danish crude is exported, chiefly to other countries in Western Europe.

Ecuador

Proved recoverable reserves (crude oil and NGLs, million tonnes)	719
Production (crude oil and NGLs, million tonnes, 2005)	27.6
R/P ratio (years)	26.1
Year of first commercial production	1917

The early discoveries of oil (1913-1921) were made in the Santa Elena peninsula on the south-west coast. From 1967 onwards, numerous oil fields were discovered in the Amazon Basin in the north-east of the country, adjacent to the Putamayo fields in Colombia: these eastern (Oriente) fields are now the major source of Ecuador's oil production.

The level of proved reserves shown above has been derived from *World Oil*'s end-2005 figure of 5 145 million barrels, as the corresponding level (4 630) reported by *Oil & Gas Journal,* the previous data source for Ecuador, appears low in comparison with *World Oil* and other published sources (OPEC 5 060; BP 5 100).

Ecuador's oil output was running at a record level in 2005, with crude oil averaging 532 000 b/d over the year, plus a small amount of NGLs. About 70% of crude production is exported, the rest being refined locally.

Egypt (Arab Republic)

Proved recoverable reserves (crude oil and NGLs, million tonnes)	495
Production (crude oil and NGLs, million tonnes, 2005)	33.9
R/P ratio (years)	14.7
Year of first commercial production	1911

Egypt has the sixth largest proved oil reserves in Africa, with over half located in its offshore waters. According to the Egyptian WEC Member Committee, Egypt's crude oil reserves were 2.9 billion barrels (408 million tonnes) at the end of 2005, together with 0.8 billion barrels (87 million tonnes) of NGLs (condensates and LPG). The main producing regions are in or alongside the Gulf of Suez and in the Western Desert.

Egypt is a member of OAPEC, although crude oil exports account for only about 3% of its production, having fallen considerably in recent years. Total oil output (including condensate and gas-plant LPGs) has been gradually declining in recent years. In 2005 crude oil production was 28.5 million tonnes (554 000 b/d), condensate production was 4.2 million tonnes (104 000 b/d), and LPGs from gas-processing plants amounted to 1.2 million tonnes (38 000 b/d).

Equatorial Guinea

Proved recoverable reserves (crude oil and NGLs, million tonnes)	245
Production (crude oil and NGLs, million tonnes, 2005)	17.6
R/P ratio (years)	13.9
Year of first commercial production	1992

The Alba offshore condensate field was discovered in 1984 near the island of Bioko, a province of Equatorial Guinea, by the American company Walter International. In 1996, four years after Alba was brought into production, Mobil and its US partner United Meridian began producing from Zafiro, another offshore field. Output built up rapidly in subsequent years: crude oil production in Equatorial Guinea averaged some 355 000 b/d in 2005.

For the purposes of the present *Survey*, the level of proved reserves published by *World Oil* (1 805 million barrels) has been adopted; *Oil & Gas Journal* has increased its assessment from 12 million barrels at end-2005 to 1 100 million at end-2006.

Gabon

Proved recoverable reserves (crude oil and NGLs, million tonnes)	294
Production (crude oil and NGLs, million tonnes, 2005)	11.7
R/P ratio (years)	25.1
Year of first commercial production	1961

Extensive oil resources have been located, both on land and offshore. In terms of proved recoverable reserves, Gabon ranks third largest in sub-Saharan Africa. The level of proved recoverable reserves adopted for the present *Survey* is that quoted by *World Oil* (2 146 million barrels). *Oil & Gas Journal* retained a level of 2 499 million barrels from 1997 to 2005, but reduced it to 2 000 million at end-2006.

Gabon was a member of OPEC from 1975 to 1995, when it withdrew on the grounds that it was unfair for it to be charged the same membership fee as the larger producers but not to have equivalent voting rights.

In recent years over 90% of Gabon's oil output has been exported, mainly to the USA.

India

Proved recoverable reserves (crude oil and NGLs, million tonnes)	786
Production (crude oil and NGLs, million tonnes, 2005)	36.3
R/P ratio (years)	21.7
Year of first commercial production	1890

Within a proved amount in place of 1 652 million tonnes, the amount of proved recoverable reserves (as at 1 April 2005) reported for this *Survey* is 786 million tonnes, of which 410 million tonnes is located offshore. Onshore reserves have risen by 13.3% from the 332 million tonnes (as at 1 April 2002) reported for the 2004 *Survey* to 376 million tonnes, whereas offshore reserves are virtually unchanged. Data for 1 April 2006 published by the Ministry of Petroleum & Natural Gas show further growth in onshore reserves to 387 million tonnes and a sharp drop in offshore, down 10% to 369 million tonnes.

For more than 60 years after its discovery in 1890, the Digboi oil field in Assam, in the northeast of the country, provided India with its only commercial oil production: this field was still producing in 2005, albeit at a very low level. Since 1960 numerous onshore discoveries have been made in the western, eastern and southern parts of India; the outstanding find was, however, made in offshore waters in 1974, when the Mumbai High oil and gas field was discovered. In 2005-2006 offshore fields provided almost 65% of national oil output.

Total production of oil (including gas-plant liquids) has fluctuated in recent years within a range of 36-38 million tonnes per annum. In 2005, India produced (in million tonnes) 32.5 crude oil, 1.4 natural gasoline and an estimated 2.4 gas-plant LPG, all of which was used internally.

Indonesia

Proved recoverable reserves (crude oil and NGLs, million tonnes)	570
Production (crude oil and NGLs, million tonnes, 2005)	54.0
R/P ratio (years)	10.6
Year of first commercial production	1893

The first commercial discovery of oil was made in north Sumatra in 1885; subsequent exploration led to the finding of many more fields, especially in southern Sumatra, Java and Kalimantan.

Proved recoverable reserves at end-2005 have been based on published data, and reflect the consensus view of *Oil & Gas Journal*, OAPEC, OPEC and BP, at a level of 4 300 million barrels. *World Oil*, while ostensibly excluding NGLs, quotes a significantly higher figure at 5 025 million barrels.

In 2004 Indonesia exported over 40% of its output of crude oil and condensate, as well as about half of its production of gas-plant LPGs. The bulk of its oil exports are consigned to Japan, the Republic of Korea, Australia and China. It has been a member of OPEC since 1962.

Iran (Islamic Republic)

Proved recoverable reserves (crude oil and NGLs, million tonnes)	17 340
Production (crude oil and NGLs, million tonnes, 2005)	204.9
R/P ratio (years)	90.5
Year of first commercial production	1913

The first commercial crude oil discovered in Iran was at Masjid-i-Sulaiman in 1908. Further exploration in the next two decades resulted in the discovery of a number of major oil fields, including Agha Jari and Gach Saran. Fields such as these confirmed Iran in its role as a global player in the oil industry.

After many years as a major oil producer, the country's oil resources are still enormous: proved reserves, as reported for the present *Survey* by the Iranian WEC Member Committee, comprise 101.19 billion barrels of crude oil plus 36.30 billion barrels of NGLs. The total reported reserves of 137.49 billion barrels are almost identical to those quoted by BP and close to those given by other standard published sources (131.50-136.27). Approximately 11.5% of the proved reserves of crude and 54% of the NGLs are located offshore.

Iran was a founder member of OPEC in 1960. In 2005, about 60% of Iran's crude oil output of 3.9 million b/d was exported, mostly to Europe and Asia.

Iraq

Proved recoverable reserves (crude oil and NGLs, million tonnes)	15 478
Production (crude oil and NGLs, million tonnes, 2005)	89.5
R/P ratio (years)	> 100
Year of first commercial production	1927

Crude oil deposits were discovered near Kirkuk in northern Iraq in 1927, with large-scale production getting under way in 1934-1935 following the construction of export pipelines to the Mediterranean. After World War II more oil fields were discovered and further export lines built. Proved reserves, as quoted by OAPEC, OPEC and all the other standard published sources, remain at 115 billion barrels, third after Saudi Arabia and Iran in the Middle East, and indeed in the world.

Iraq was a founder member of OPEC in 1960 and it is also a member of OAPEC. According to provisional data published by OPEC, crude oil exports amounted to almost 1.5 million b/d in 2005, with 55% destined for the USA and 27% for Western Europe.

Italy

Proved recoverable reserves (crude oil and NGLs, million tonnes)	106
Production (crude oil and NGLs, million tonnes, 2005)	6.1
R/P ratio (years)	17.3
Year of first commercial production	1861

Like France and Germany, Italy has a long history of oil production, albeit on a very small scale until the discovery of the Ragusa and Gela fields in Sicily in the mid-1950s. Subsequent exploration led to the discovery of a number of fields offshore Sicily, several in Adriatic waters and others onshore in the Po Valley Basin.

The Italian WEC Member Committee reports that proved recoverable reserves at end-2005 were 106 million tonnes (equivalent to some 744 million barrels). It also estimates that the additional amount of oil in place is in the order of 400-2 700 million barrels (say, 60-380 million tonnes).

Total oil output (including minor quantities of NGLs) in 2005 was at a record annual level.

Kazakhstan

Proved recoverable reserves (crude oil and NGLs, million tonnes)	5 013
Production (crude oil and NGLs, million tonnes, 2005)	62.6
R/P ratio (years)	80.1
Year of first commercial production	1911

Kazakhstan's oil resources are the largest of all the former Soviet republics (apart from the Russian Federation). For the purposes of the present *Survey*, the level of Kazakhstan's proved recoverable reserves is based on the figure of 39 600 million barrels published by BP in its *Statistical Review of World Energy, 2006*. Other published estimates have yet to catch up with this level, although *Oil & Gas Journal* has jumped from 9 billion barrels at end-2005 to 30 billion at end-2006.

Most of the republic's oil fields are in the north and west of the country. Output of oil more than doubled between 1999 and 2005 to over 62 million tonnes (1 356 000 b/d), including 11.7 million tonnes (338 000 b/d) of NGLs, condensate and LPG. In 2004, exports accounted for 86% of the republic's oil production.

Kuwait

Proved recoverable reserves (crude oil and NGLs, million tonnes)	13 679
Production (crude oil and NGLs, million tonnes, 2005)	130.1
R/P ratio (years)	> 100
Year of first commercial production	1946

Note: Kuwait data include its share of Neutral Zone.

The State of Kuwait is one of the most oil-rich countries in the world: it currently ranks fourth in terms of the volume of proved reserves. Oil was discovered at Burgan in 1938 and commercial production commenced after World War II. Seven other oil fields were discovered during the next 15 years and output rose rapidly. Kuwait was one of the founder members of OPEC in 1960 and is also a member of OAPEC.

The level of proved recoverable reserves adopted for the present *Survey* is 101.5 billion barrels, as quoted by OAPEC, OPEC and BP, (and by *Oil & Gas Journal* for end-2006). *World Oil* gives a slightly lower figure: 100.875 billion barrels.

Kuwait's crude production in 2005 averaged 2.64 million b/d, of which 1.65 million b/d, or 62%, was exported. The main markets for Kuwaiti crude were Japan, other Asian countries, North America and Western Europe.

Libya/GSPLAJ

Proved recoverable reserves (crude oil and NGLs, million tonnes)	5 350
Production (crude oil and NGLs, million tonnes, 2005)	80.1
R/P ratio (years)	66.7
Year of first commercial production	1961

With proved oil reserves of 41 464 million barrels, Libya accounts for 32% of the total for Africa. The majority of the known oil reservoirs lie in the northern part of the country; there are a few offshore fields in western waters near the Tunisian border. The crudes produced are generally light (over 35^{o} API) and very low in sulphur.

The level of proved reserves adopted for the present *Survey* is based upon data published by OPEC in its *Annual Statistical Bulletin 2005*, and is some 6% higher than the level quoted by OAPEC in its 2005 *Annual Report* and by BP and *Oil & Gas Journal* (although the latter publication quotes 41 464 for end-2006). *World Oil* gives a lower figure (34 050) for reserves of crude oil (excluding NGLs).

Libya joined OPEC in 1962 and is also a member of OAPEC. It exported about 77% of its oil output in 2005, almost all to Western Europe.

Malaysia

Proved recoverable reserves (crude oil and NGLs, million tonnes)	365
Production (crude oil and NGLs, million tonnes, 2005)	36.8
R/P ratio (years)	9.9
Year of first commercial production	1913

Oil was discovered at Miri in northern Sarawak in 1910, thus ushering in Malaysia's long history as an oil producer. However, it was not until after successful exploration in offshore areas of Sarawak, Sabah and peninsular Malaysia in the 1960s and 1970s that the republic really emerged as a major producer.

Proved reserves, as reported by *Oil & Gas Journal*, remained in the vicinity of 4 billion barrels from the early 1990s to end-2001, when they were reduced to 3 billion barrels, a level retained for end-2005. OPEC quotes the same level and *World Oil* a slightly lower figure (possibly reflecting its policy of excluding NGLs), whereas BP's assessment is substantially higher, at 4 200 million barrels.

After following a rising trend since 2001, crude oil production fell by 8.5% in 2005; however condensate output rose sharply to a new peak. In 2004, over 50% of Malaysian crude oil production was exported, chiefly to Thailand, the Republic of Korea, Indonesia, Japan and India.

Mexico

Proved recoverable reserves (crude oil and NGLs, million tonnes)	1 847
Production (crude oil and NGLs, million tonnes, 2005)	187.1
R/P ratio (years)	10.0
Year of first commercial production	1904

Mexico's massive oil resource base has given rise to one of the world's largest oil industries, centred on the national company Petróleos Mexicanos (Pemex), founded in 1938.

The Mexican WEC Member Committee has reported proved recoverable reserves (at end-2005) of 11 814 million barrels of crude oil and 1 857 million barrels of NGLs, which correspond with the 'proved reserves' given by Pemex in its *Informe Estadístico de Labores 2005*. Pemex quotes its proved reserves (in terms of millions of barrels), as: crude oil 11 813.8, condensate 537.9 and gas-plant liquids 1 318.8. In addition to these 'proved' oil reserves (totalling 13 670.5), 'probable' reserves are given as 12 857.2 and 'possible' reserves as 10 907.6.

Within Mexico's total oil reserves of 37.4 billion barrels, the North zone accounts for 39.0%, the Marine Northeast for 38.7%, the South zone for 13.4% and the Marine Southwest for 8.9%. As regards its proved reserves, 69% of the crude oil, 78% of the condensate and 33% of the gas-plant liquids are located in offshore waters.

Commercial oil production began in 1904 and by 1918 the republic was the second largest producer in the world. The discovery and development of oil fields along the eastern coast of the country - in particular, the offshore reservoirs off the coast of the state of Campeche - have brought annual production up to its present level. In 2005 oil output comprised 3 333 tb/d crude oil, 89 tb/d condensate and 338 tb/d gas-plant liquids; exports of crude totalled 1 817 tb/d, of which some 78% was consigned to the USA.

Nigeria

Proved recoverable reserves (crude oil and NGLs, million tonnes)	4 823
Production (crude oil and NGLs, million tonnes, 2005)	125.4
R/P ratio (years)	38.5
Year of first commercial production	1957

Nigeria's proved oil reserves are the second largest in Africa, after those of Libya. The country's oil fields are located in the south, mainly in the Niger delta and offshore in the Gulf of Guinea. Nigeria has been a member of OPEC since 1971.

Published assessments of Nigeria's proved recoverable reserves (as at end-2005) are now close to consensus, after divergences in earlier years. For the purposes of the present *Survey*, the level of 36 220 million barrels reported by OPEC (*Annual Statistical Bulletin 2005*) has been adopted. Other published sources quote very similar figures, within a narrow range (35 876 to 37 175). The latest OPEC level for Nigerian reserves is some 15% higher than its comparable assessment for end-2002, as used in the 2004 *Survey*.

Nigeria exported much the greater part of its crude oil output in 2005, to a wide spread of regions throughout the world, and imported the bulk of its refined product requirements.

Norway

Proved recoverable reserves (crude oil and NGLs, million tonnes)	1 202
Production (crude oil and NGLs, million tonnes, 2005)	138.2
R/P ratio (years)	8.8
Year of first commercial production	1971

Starting with the discovery of the Ekofisk oil field in 1970, successful exploration in Norway's

North Sea waters has brought the country into No. 1 position in Europe (excluding the Russian Federation), in terms of oil in place, proved reserves and production.

On the basis of data published by the Norwegian Petroleum Directorate (NPD), total oil reserves at end-2005 amounted to 1 230 million m^3 (approximately 1 034 million tonnes) of crude oil, 138 million tonnes of NGLs and 47 million m^3 (about 30 million tonnes) of condensate. In addition to the quoted proved amount, the NPD reports 'contingent resources', defined as 'discovered quantities of petroleum for which no development decision has yet been made', and 'potential from improved recovery': together these represent 585 million m^3 (492 million tonnes) of crude oil, 47 million tonnes of NGLs and 41 million m^3 (26 million tonnes) of condensate – a total additional recoverable resource of 565 million tonnes. Over and above these amounts, there are estimated to be 'undiscovered resources' of 1 160 million m^3 (975 million tonnes) of crude oil and 340 million m^3 (218 million tonnes) of condensate.

Although Norway's recoverable reserves are 2.4 times those of the UK, its oil output in 2005 was only about 65% higher than that of the UK. Following 16 years of unremitting growth, Norwegian oil production levelled off in the late 1990s and since 2001 has been on a gently downward trend. The groups of fields with the largest output of crude oil in 2005 were Ekofisk, Troll, Grane, Snorre, Gullfaks, Heidrun and Asgard. Nearly 90% of Norwegian crude oil production was exported in 2005, mostly to Western European countries, the USA and Canada.

Oman

Proved recoverable reserves (crude oil and NGLs, million tonnes)	746
Production (crude oil and NGLs, million tonnes, 2005)	38.5
R/P ratio (years)	19.4
Year of first commercial production	1967

In a regional context, this is one of the less well-endowed Middle East countries but its proved reserves are, nevertheless, quite substantial (5.51 billion barrels at end-2005, according to OAPEC). Other published sources of reserves data generally concur.

Three oil fields were discovered in the north-west central part of Oman in the early 1960s; commercial production began after the construction of an export pipeline. Many other fields have subsequently been located and brought into production, making the country a significant oil producer and exporter; it has, however, never joined OPEC or OAPEC. Production levels steadily increased over the years but peaked in 2001, subsequently falling to an average of 780 000 b/d in 2005. A high proportion of Oman's crude oil output is exported, mainly to Japan, Southeast Asia and China.

Papua New Guinea

Proved recoverable reserves (crude oil and NGLs, million tonnes)	31
Production (crude oil and NGLs, million tonnes, 2005)	2.2
R/P ratio (years)	14.0
Year of first commercial production	1992

Five sedimentary basins are known to exist in PNG. Most exploration activity, and all hydrocarbon discoveries to date, have occurred in the Papuan Basin in the southern part of the mainland. After many campaigns of exploration (starting in 1911), the first commercial discoveries were eventually made during the second half of the 1980s. Commercial production began in 1992 after an export pipeline had been built.

The level quoted for proved recoverable reserves reflects *Oil & Gas Journal*'s unchanged estimate of 240 million barrels. The oil exported is a blend called Kutubu Light (45^{o} API). Output in 2005 averaged 47 000 b/d.

Peru

Proved recoverable reserves (crude oil and NGLs, million tonnes)	117
Production (crude oil and NGLs, million tonnes, 2005)	4.9
R/P ratio (years)	26.5
Year of first commercial production	1883

Peru is probably the oldest commercial producer of oil in South America. The WEC Member Committee reports that proved recoverable reserves at end-2005 consisted of 382.9 million barrels of crude oil and 695.4 million barrels of NGL, reflecting data published by the Ministerio de Energía y Minas, and equivalent in rounded terms to 52 and 65 million tonnes, respectively. The reported total of 1 078 million barrels corresponds quite closely with the levels published by *World Oil* and BP, but *Oil & Gas Journal* comes out somewhat lower at 930 million barrels, despite having raised its assessment substantially from the 323 million barrels it had quoted for end-2002.

The Ministerio de Energía y Minas also quotes (in million barrels) 'probable reserves' of 438.1 crude and 294.3 NGL, and 'possible reserves' of 5 418.1 crude and 384.1 NGL.

For many years oil production was centred on the fields in the Costa (coastal) area in the northwest; from about 1960 onwards the Zocalo (continental shelf) off the north-west coast and the Selva (jungle) area east of the Andes came into the picture. In 2005 the Selva fields accounted for 73% of total oil output, the Costa fields for 17% and the Zocalo for nearly 10%. Production of crude oil has for some time followed a gently downward slope, but output of NGLs has recently been growing rapidly.

Qatar

Proved recoverable reserves (crude oil and NGLs, million tonnes)	1 852
Production (crude oil and NGLs, million tonnes, 2005)	45.8

R/P ratio (years)	40.6
Year of first commercial production	1949

In regional terms, Qatar's oil resources are relatively small, its strength being much more in natural gas. In the 1930s interest in its prospects was aroused by the discovery of oil in neighbouring Bahrain. The Dukhan field was discovered in 1939 but commercialisation was deferred until after World War II. During the period 1960-1970, several offshore fields were found, and Qatar's oil output grew steadily. It joined OPEC in 1961 and also became a member of OAPEC.

The level of proved recoverable oil reserves (15 207 million barrels) retained for the present *Survey* is that quoted by OPEC in its *Annual Statistical Bulletin 2005*. Currently BP and OAPEC (both in slightly rounded form) and *Oil & Gas Journal* all concur with OPEC's assessment, but *World Oil* is one-third higher at 20 346 million barrels.

Qatar is a major producer of NGLs: its 2005 output was more than 9 million tonnes (262 000 b/d). Exports of crude oil and NGLs are consigned very largely to Japan, the Republic of Korea and other Asia/Pacific countries.

Romania

Proved recoverable reserves (crude oil and NGLs, million tonnes)	53
Production (crude oil and NGLs, million tonnes, 2005)	5.3
R/P ratio (years)	9.8
Year of first commercial production	1857

Despite being one of Europe's oldest oil producers, Romania still possesses substantial oil resources. The Romanian WEC Member Committee, quoting the National Agency for Mineral Resources, reports that within a proved amount of crude oil in place of 1 947 million tonnes, plus a corresponding figure of 11 million tonnes for NGLs, recoverable reserves are 52.1 million tonnes of crude plus 0.6 million tonnes of NGLs. The estimated additional amounts in place (in million tonnes) are given as approximately 124 and 2, respectively, with recoverable amounts of 62 and 0.4.

The principal region of production has long been the Ploesti area in the Carpathian Basin to the north-west of Bucharest, but a new oil province has come on the scene in recent years with the start-up of production from two offshore fields (West and East Lebada) in the Black Sea. Within the figures of proved recoverable reserves given above, the amounts located in offshore waters are 1.6 million tonnes of crude oil and 0.2 million tonnes of NGLs. In national terms, oil output (including NGLs) has been slowly contracting since around 1995.

Russian Federation

Proved recoverable reserves (crude oil and NGLs, million tonnes)	10 027
Production (crude oil and NGLs, million tonnes, 2005)	470.2
R/P ratio (years)	21.3

The Russian oil industry has been developing for well over a century, much of that time under the Soviet centrally planned and state-owned system, in which the achievement of physical production targets was of prime importance. After World War II, hydrocarbons exploration and production development shifted from European Russia to the east, with the opening-up of the Volga-Urals and West Siberia regions.

As the Russian WEC Member Committee was unable to supply up-to-date assessments of hydrocarbon reserves, for reasons of confidentiality, the level of proved recoverable reserves adopted for the present *Survey* is based on the figure of 74 400 million barrels published by *World Oil* and BP. *Oil & Gas Journal* has retained its estimate of 60 billion barrels for both end-2005 and end-2006, whilst OAPEC has opted for an intermediate level of 72 160 million barrels.

Production levels in Russia advanced strongly from the mid-1950s to around 1980 when output levelled off for a decade. After a sharp decline in the first half of the 1990s, oil production levelled off again, at around 305 million tonnes/yr, until an upturn starting in 2000 brought the total up to 470 million tonnes in 2005. Russia exports more than half of its oil production.

Saudi Arabia

Proved recoverable reserves (crude oil and NGLs, million tonnes)	34 550
Production (crude oil and NGLs, million tonnes, 2005)	526.2
R/P ratio (years)	65.6
Year of first commercial production	1936

Note: Saudi Arabia data include its share of Neutral Zone, together with production from the Abu Safa oilfield (jointly owned with Bahrain).

The Kingdom has been a leading oil producer for more than 40 years and currently has by far the world's largest proven reserves of oil: at end-2005 these represented about 22% of the global total. The first major commercial discovery of oil in Saudi Arabia was the Dammam field, located by Aramco in 1938; in subsequent years the company discovered many giant fields, including Ghawar (1948), generally regarded as the world's largest oil field, and Safaniyah (1951), the world's largest offshore field.

Whilst not displaying an exact consensus, current published assessments of Saudi Arabia's proved oil reserves at end-2005 fall within a narrow bracket: namely (in billions of barrels), *World Oil* 262.175, BP 264.200, OPEC 264.211, OAPEC (as used in this *Survey*) 264.310. and *Oil & Gas Journal* 266.81 (262.300 at end-2006).

Saudi Arabia was a founder member of OPEC and also of OAPEC. It exports about three-quarters of its crude oil output; major destination regions are Asia, North America and Western Europe.

Sudan

Proved recoverable reserves (crude oil and NGLs, million tonnes)	864
Production (crude oil and NGLs, million tonnes, 2005)	17.5

R/P ratio (years)	49.4
Year of first commercial production	1992

Several oil fields, including Heglig and Unity, were discovered in south-central Sudan in the early 1980s but terrorist action forced the companies concerned to withdraw. Other foreign companies started to undertake exploration and development activities some 10 years later. Most published sources quote Sudan's proved recoverable reserves at end-2005 as lying within a narrow range: (in millions of barrels) OAPEC 6 320; BP 6 400; *World Oil* 6 402 (adopted for the present *Survey*) and OPEC 6 405. The one exception is *Oil & Gas Journal*, which showed only 563 million barrels for reserves at end-2005, but has increased them to 5 billion barrels as at-end 2006.

Commercial production from the Heglig field began in 1996, since when Sudan has developed into an oil producer and exporter of some significance, a key factor being the construction of a 250 000 b/d export pipeline to the Red Sea. Sudan's oil production in 2005 averaged 355 000 b/d.

Syria (Arab Republic)

Proved recoverable reserves (crude oil and NGLs, million tonnes)	335
Production (crude oil and NGLs, million tonnes, 2005)	20.6
R/P ratio (years)	16.3
Year of first commercial production	1968

After many years (1930-1951) of unsuccessful exploration, oil was eventually found in 1956 at Karachuk. This and other early discoveries mostly consisted of heavy, high-sulphur crudes. Subsequent finds, in particular in the Deir al-Zor area in the valley of the Euphrates, have tended to be of much lighter oil.

The Syrian WEC Member Committee reports that proved recoverable reserves are 391 million m^3 (2 459 million barrels). This level looks rather more convincing than the obviously very rounded estimates given by published sources: *Oil & Gas Journal* 2 500; *World Oil*, OPEC and BP 3 000 and OAPEC 3 150.

National oil output has declined fairly sharply in recent years, to 414 000 b/d in 2005, of which about half was exported. Syria's principal customers for its crude oil in 2005 were Germany, Italy and France; it is a member of OAPEC.

Thailand

Proved recoverable reserves (crude oil and NGLs, million tonnes)	51
Production (crude oil and NGLs, million tonnes, 2005)	10.8
R/P ratio (years)	6.8
Year of first commercial production	1959

Resources of crude oil and condensate are not very large in comparison with many other countries in the region. The data reported by the Thai WEC Member Committee for the present *Survey* show proved reserves of oil as 192 million barrels of crude oil and 261 million barrels of condensate. Just over three-quarters of the crude reserves and virtually all of the condensate reserves are located in Thailand's offshore waters. Data on reserves of other NGLs were not provided; consequently the calculated reserves/production ratio shown above is based on crude-plus-condensate production data.

The estimated additional amounts in place are reported as 195 million barrels of crude and 451 million barrels of condensate, of which the recoverable reserves are 119 and 293 million barrels respectively, implying recovery factors of 0.61 for crude and 0.65 for condensate.

Total output of oil (crude oil, condensate and other NGLs) has more than doubled since 1999, with an average of about 264 000 b/d in 2005. Exports of crude oil have risen sharply in recent years, averaging nearly 66 000 b/d in 2005.

Trinidad & Tobago

Proved recoverable reserves (crude oil and NGLs, million tonnes)	81
Production (crude oil and NGLs, million tonnes, 2005)	8.3
R/P ratio (years)	9.9
Year of first commercial production	1908

The petroleum industry of Trinidad has passed its centenary, several oil fields that are still in production having been discovered in the first decade of the 20th century. The remaining recoverable reserves are small in regional terms, at 615 million barrels, as reported by the Trinidad & Tobago WEC Member Committee. Whilst *World Oil* quotes an identical figure, BP shows 800 and *Oil & Gas Journal* has 990 for end-2005 but only 728 for end-2006.

The oil fields that have been discovered are mostly in the southern part of the island or in the corresponding offshore areas (in the Gulf of Paria to the west and off Galeota Point at the south-east tip of the island).

After ten years of moderate oscillation around a mean level of 112 000 b/d, output of crude oil rose sharply to 126 000 b/d in 2005; condensate output was also well up at 18 000 b/d. Production of gas-plant NGLs began in 1991 and averaged about 27 000 b/d in 2005. Over 40% of Trinidad's crude output is exported.

Turkmenistan

Proved recoverable reserves (crude oil and NGLs, million tonnes)	74
Production (crude oil and NGLs, million tonnes, 2005)	9.5
R/P ratio (years)	7.8
Year of first commercial production	1911

This republic has been an oil producer for nearly a century, with a cumulative output of more that 5 billion barrels. According to *Oil & Gas Journal*, proved reserves are 546 million barrels, unchanged since the 1998 edition of the SER. Known hydrocarbon resources are located in two main areas: the South Caspian Basin to the west and the Amu-Darya Basin in the eastern half of the country. After growth averaging nearly

12% per annum from 1995 to 2003, oil output (including NGLs) fell by around 5% over the two years that followed.

United Arab Emirates

Proved recoverable reserves (crude oil and NGLs, million tonnes)	12 555
Production (crude oil and NGLs, million tonnes, 2005)	129.0
R/P ratio (years)	97.4
Year of first commercial production	1962

The United Arab Emirates comprises Abu Dhabi, Dubai, Sharjah, Ras al-Khaimah, Umm al-Qaiwain, Ajman and Fujairah. Exploration work in the three last-named has not found any evidence of oil deposits on a commercial scale. On the other hand, the four emirates endowed with oil resources have, in aggregate, proved reserves on a massive scale, in the same bracket as those of Iran, Iraq and Kuwait. Abu Dhabi has by far the largest share of UAE reserves and production, followed at some distance by Dubai. The other two oil-producing emirates are relatively minor operators.

The UAE's proved oil reserves at end-2005 are quoted by OAPEC as 97.8 billion barrels, a level virtually unchanged since 1990. According to OPEC, quoting the same total figure, Abu Dhabi accounts for 94.3% of proved reserves, Dubai for 4.1%, Sharjah for 1.5% and Ras al-Khaimah for 0.1%.

Total crude output (including a considerable amount of production offshore) amounted to about 2.75 million b/d in 2005, of which the bulk was exported, almost all to Japan and other Asia/Pacific destinations. The UAE has been a member of OPEC since 1967 and is also a member of OAPEC.

United Kingdom

Proved recoverable reserves (crude oil and NGLs, million tonnes)	516
Production (crude oil and NGLs, million tonnes, 2005)	84.7
R/P ratio (years)	6.1
Year of first commercial production	1919

Proved recoverable reserves are stated by the Department of Trade and Industry in *UK Oil and Gas Reserves* (September 2006) to be 516 million tonnes at end-2005. This figure compares with the United Kingdom's cumulative oil production of some 3 090 million tonnes.

In addition, there are estimated to be 300 million tonnes of 'probable reserves', with 'a better than 50% chance of being technically and economically producible', and a further 451 million tonnes of 'possible reserves', with 'a significant but less than 50% chance of being technically and economically producible'.

Total output of crude oil and NGLs increased from about 92 million tonnes/yr in 1989-1991 to an all-time high of 137 million tonnes in 1999, since when production has tended to decline. The UK exported 64% of its total oil output in 2005; 64% of such exports were consigned to EU countries and 26% to the USA.

United States of America

Proved recoverable reserves (crude oil and NGLs, million tonnes)	3 691
Production (crude oil and NGLs, million tonnes, 2005)	313.3
R/P ratio (years)	11.9
Year of first commercial production	1859

The United States has one of the largest and oldest oil industries in the world. Although its remaining recoverable reserves are dwarfed by some of the Middle East producers, it is the third largest oil producer, after Saudi Arabia and the Russian Federation.

Proved reserves at end-2005, as published by the Energy Information Administration of the US Department of Energy in December 2006, were 21 757 million barrels of crude oil and 8 165 million barrels of NGLs. Compared with the levels at end-2002, crude reserves are 4.1% lower and those of NGLs up by 2.1%. The 920 million barrel net decrease in crude reserves was the result of 3 065 from extensions and discoveries in old and new fields, plus revisions and adjustments of 1 444, minus crude production of 5 429. The comparable figures for NGLs (also in millions of barrels) are 2 487 from extensions and discoveries, plus 101 net revisions, etc. less 2 417 production, giving a net increase of 171 in proved reserves.

Crude oil production in 2005 was 5 178 000 b/d and that of NGLs (including 'pentanes plus') was 1 717 000 b/d. The USA exported 41 000 b/d of crude oil in 2005, almost all to Canada.

Uzbekistan

Proved recoverable reserves (crude oil and NGLs, million tonnes)	70
Production (crude oil and NGLs, million tonnes, 2005)	5.5
R/P ratio (years)	12.8

Although an oil producer for more than a century, large-scale developments in the republic mostly date from after 1950. The current assessment published by *Oil & Gas Journal* shows proved reserves as 594 million barrels, a level unchanged since 1996. Oil fields discovered so far are located in the south-west of the country (Amu-Darya Basin) and in the Tadzhik-Fergana Basin in the east.

Total oil output (including NGLs) followed a rising trend for about 10 years from 1988, since when the trend has been moderately negative, more sharply so in 2004 and 2005. All of Uzbekistan's production of crude and condensate is processed in domestic refineries or used directly as feedstock for petrochemicals.

Venezuela

Proved recoverable reserves (crude oil and NGLs, million tonnes)	11 269
Production (crude oil and NGLs, million tonnes, 2005)	154.7
R/P ratio (years)	72.9
Year of first commercial production	1917

The oil resource base is truly massive, and proved recoverable reserves are easily the largest of any country in the Western Hemisphere. Starting in 1910, hydrocarbons exploration established the existence of four petroliferous basins: Maracaibo (in and around the lake), Apure to the south of the lake, Falcón to the north-east and Oriental in eastern Venezuela. The republic has been a global-scale oil producer and exporter ever since the 1920s, and was a founder member of OPEC in 1960.

The level adopted for end-2005 proved recoverable reserves of crude oil and natural gas liquids is 80 012 million barrels, as given by OPEC in its *Annual Statistical Bulletin 2005* (published 2006). *Oil & Gas Journal*, OAPEC and BP all quote figures in the region of 79 700; OGJ has moved up to the OPEC level of 80 012 for its end-2006 assessment. The only exception to the general consensus is *World Oil*, which quotes 52 650 million barrels, a figure that would exclude NGLs and probably extra-heavy oil.

According to *Petróleo y Otros Datos Estadísticos 2004*, published in October 2006 by the Ministerio de Energía y Petróleo about 58% of national oil output in 2004 came from the Oriental Basin, 39% from the Maracaibo, 3% from the Apure and a minimal proportion from the Falcón Basin. Of total crude oil output of 3 143 000 b/d in 2004 (including condensate and bitumen for Orimulsion® (registered trade mark belonging to Bitúmenes Orinoco S.A.)), 1 774 000 b/d (56.4%) was exported, the bulk of which being consigned to North and South America: the United States took nearly 57% of Venezuela's crude exports.

Vietnam

Proved recoverable reserves (crude oil and NGLs, million tonnes)	413
Production (crude oil and NGLs, million tonnes, 2005)	19.1
R/P ratio (years)	21.7
Year of first commercial production	1986

During the first half of the 1980s oil was discovered offshore in three fields (Bach Ho, Rong and Dai Hung), and further discoveries have since been made. For the present *Survey*, proved recoverable reserves (3 100 million barrels) have been derived from BP's latest published assessment (*Statistical Review of World Energy, 2006*). *World Oil* shows 1 345 million barrels, whilst a third source (*Oil & Gas Journal*) continues to quote a level of only 600 million barrels, which would imply an unrealistically low R/P ratio of 4.2. Production of crude oil (averaging 34° API) began in 1986 and rose steadily until 2004, but fell by about 8% the following year. At present all output is exported.

Yemen

Proved recoverable reserves (crude oil and NGLs, million tonnes)	384
Production (crude oil and NGLs, million tonnes, 2005)	19.8
R/P ratio (years)	19.3
Year of first commercial production	1986

After many years of fruitless searching, exploration in the 1980s and 1990s brought a degree of success, with the discovery of a number of fields in the Marib area, many yielding very light crudes. Oil discoveries have been made in two other areas of the country (Shabwa and Masila) and Yemen has evolved into a fairly substantial producer and exporter of crude.

The level of proved recoverable reserves quoted by OAPEC has remained at 4 billion barrels for the past 13 years. *Oil & Gas Journal* gave the same level for end-2005 but has reduced its estimate to 3 billion as at end-2006. BP, in its *Statistical Review of World Energy, 2006*, quotes 2 900 million barrels. For the purposes of the present *Survey*, the latest assessment by *World Oil* – 2 970 million barrels – has been adopted.

Total output in 2005 was 422 000 b/d (including 22 000 b/d of NGLs). About three-quarters of Yemen's crude production is exported, largely to Singapore, Japan, the Republic of Korea and other Asia/Pacific destinations.

3. Oil Shale

COMMENTARY

COMMENTARY[2]

Introduction

Oil shales ranging from Cambrian to Tertiary in age occur in many parts of the world. Deposits range from small occurrences of little or no economic value to those of enormous size that occupy thousands of square kilometres and contain many billions of barrels of potentially extractable shale oil. Total world resources of shale oil are conservatively estimated at 2.8 trillion barrels (Table 3-1). However, petroleum-based crude oil is cheaper to produce today than shale oil because of the additional costs of mining and extracting the energy from oil shale.

Because of these higher costs, only a few deposits of oil shale are currently being exploited – in Brazil, China, Estonia, Germany and Israel. However, with the continuing decline of petroleum supplies, accompanied by increasing costs of petroleum-based products, oil shale presents opportunities for supplying some of the fossil energy needs of the world in the years ahead.

Definition of Oil Shale

Most oil shales are fine-grained sedimentary rocks containing relatively large amounts of organic matter (known as 'kerogen') from which significant amounts of shale oil and combustible

[2] This Commentary is based on a paper first published by the Energy Minerals Division of the American Association of Petroleum Geologists, 27 February 2000. It has been edited for inclusion in this Survey.

Total world resources of shale oil are conservatively estimated at 2.8 trillion barrels.

gas can be extracted by destructive distillation. Included in most definitions of 'oil shale', either stated or implied, is the potential for the profitable extraction of shale oil and combustible gas or for burning as a fuel.

The organic matter in oil shale is composed chiefly of carbon, hydrogen, oxygen, and small amounts of sulphur and nitrogen. It forms a complex macromolecular structure that is insoluble in common organic solvents (e.g. carbon disulphide). The organic matter (OM) is mixed with varied amounts of mineral matter (MM) consisting of fine-grained silicate and carbonate minerals. The ratio of OM:MM for commercial grades of oil shale is about 0.75:5 to 1.5:5. Small amounts of bitumen that are soluble in organic solvents are present in some oil shales. Because of its insolubility, the organic matter must be retorted at temperatures of about 500°C to decompose it into shale oil and gas. Some organic carbon remains with the shale residue after retorting but can be burned to obtain additional energy. Oil shale differs from coal whereby the organic matter in coal has a lower atomic H:C ratio, and the OM:MM ratio of coal is usually greater than 4.75:5.

Origin of Oil Shale

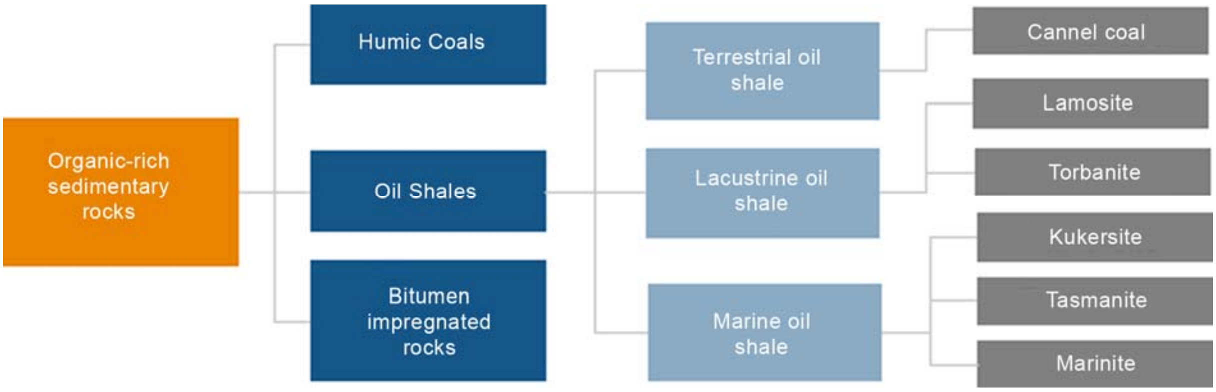
Oil shales were deposited in a wide variety of environments, including freshwater to saline ponds and lakes, epicontinental marine basins and related subtidal shelves. They were also deposited in shallow ponds or lakes associated with coal-forming peat in limnic and coastal swamp depositional environments. It is not surprising, therefore, that oil shales exhibit a wide range in organic and mineral composition. Most oil shales were formed under dysaerobic or anaerobic conditions that precluded the presence of burrowing organisms that could have fed on the organic matter. Many oil shales show well-laminated bedding attesting to a low-energy environment free of strong currents and wave action. In the oil shale deposits of the Green River Formation in Colorado and Utah, numerous beds, and even individual laminae, can be traced laterally for many kilometres. Turbiditic sedimentation is evidenced in some deposits as well as contorted bedding, microfractures, and faults.

Most oil shales contain organic matter derived from varied types of marine and lacustrine algae, with some debris of land plants, depending upon the depositional environment and sediment sources. Bacterial processes were probably important during the deposition and early diagenesis of most oil shales. Such processes could produce significant quantities of biogenic methane, carbon dioxide, hydrogen sulphide, and ammonia. These gases in turn could react with dissolved ions in the sediment waters to form authigenic carbonate and sulphide minerals such as calcite, dolomite, pyrite, and even such rare authigenic minerals as buddingtonite, an ammonium feldspar.

Classification of Oil Shales

Oil shales, until recent years, have been an enigmatic group of rocks. Many were named after a locality, mineral or algal content, or the

Figure 3-1 Classification of organic-rich rocks
Source: from Hutton, 1987



type of product the shale yielded. The following are some names that have been applied to oil shales, a few of which are still in use today:

- algal coal
- alum shale
- bituminite
- boghead coal
- cannel coal
- gas coal
- kerosene shale
- kukersite
- schistes bitumineux
- stellarite
- tasmanite
- torbanite
- wollongongite

A.C. Hutton (1987) developed a workable scheme for classifying oil shales on the basis of their depositional environments and by differentiating components of the organic matter with the aid of ultraviolet/blue fluorescent microscopy (Fig. 3-1). His classification has proved useful in correlating components of the organic matter with the yields and chemistry of the oil obtained by retorting.

Hutton divided the organic-rich sedimentary rocks into three groups. These groups are (1) humic coals and carbonaceous shales, (2) bitumen-impregnated rock (tar sands and petroleum reservoir rocks), and (3) oil shale. On the basis of the depositional environment, three basic groups of oil shales were recognised: terrestrial, lacustrine, and marine. Terrestrial oil shales include those composed of lipid-rich organic matter such as resins, spores, waxy cuticles, and corky tissue of roots and stems of vascular terrestrial plants commonly found in coal-forming swamps and bogs. Lacustrine oil shales are those containing lipid-rich organic matter derived from algae that lived in freshwater, brackish, or saline lakes. Marine oil shales are composed of lipid-rich organic matter derived from marine algae, acritarchs (unicellular microorganisms of questionable origin), and marine dinoflagellates (one-celled organisms with a flagellum).

Hutton (1987) recognised three major macerals in oil shale: telalginite, lamalginite, and bituminite. Telalginite is defined as structured organic matter composed of large colonial or thick-walled unicellular algae such as Botryococcus and Tasmanites. Lamalginite includes thin-walled colonial or unicellular algae that occur as distinct laminae, but displays little or no recognisable biologic structures. Under the microscope, telalginite and lamalginite are easily recognised by their bright shades of yellow under ultraviolet/blue fluorescent light. The third maceral, bituminite, is another important component in many oil shales. It is largely amorphous, lacks recognisable biologic structures, and displays relatively low fluorescence under the microscope. This

The potential oil shale resources of the world have barely been touched.

material has not been fully characterised with respect to its composition or origin, although it is often a quantitatively important component of the organic matter in many marine oil shales. Other organic constituents include vitrinite and inertinite, which are macerals derived from the humic matter of land plants. These macerals are usually found in relatively small amounts in most oil shales.

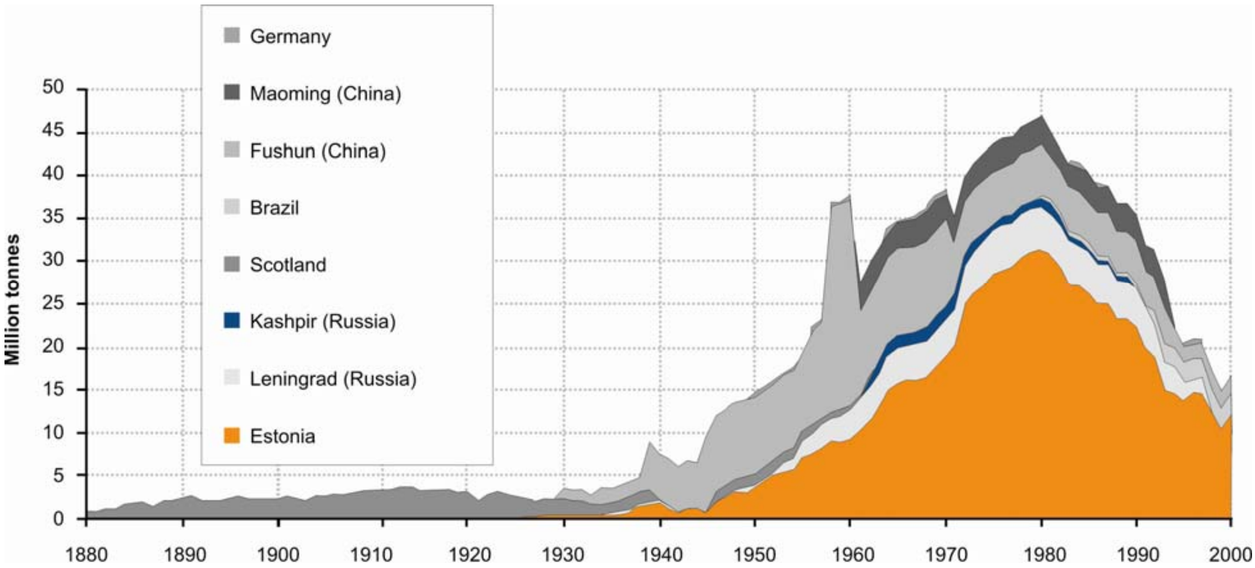
History of the Oil Shale Industry

The use of oil shale can be traced back to ancient times. By the 17th century, oil shales were being exploited in several countries. One of the interesting oil shales is the Swedish alum shale of Cambrian and Ordovician age that is noted for its alum content and high concentrations of metals including uranium and vanadium. As early as 1637, the alum shales were roasted over wood fires to extract potassium aluminium sulphate, a salt used in tanning leather and for fixing colours in fabrics. Late in the 1800s, the alum shales were retorted on a small scale for hydrocarbons. Production continued through World War II but ceased in 1966 because of the availability of cheaper supplies of petroleum crude oil. In addition to hydrocarbons, some hundreds of tonnes of uranium and small amounts of vanadium were extracted from the Swedish alum shales in the 1960s (Andersson et al., 1985).

An oil shale deposit at Autun, France, was exploited commercially as early as 1839. The Scottish oil shale industry began about 1859, the year that Colonel Drake drilled his pioneer well at Titusville, Pennsylvania. As many as 20 beds of oil shale were mined at different times. Mining continued throughout the 1800s and by 1881 oil shale production had reached 1 million tonnes per year. With the exception of the World War II years, between 1 and 4 million tonnes of oil shale were mined each year in Scotland from 1881 until 1955, when production began to decline, before ceasing in 1962. Canada produced some shale oil from deposits in New Brunswick and Ontario in the mid-1800s.

Common products made from oil shale from these early operations were kerosine and lamp oil, paraffin wax, fuel oil, lubricating oil and grease, naphtha, illuminating gas, and the fertiliser chemical, ammonium sulphate. With the introduction of the mass production of automobiles and trucks in the early 1900s, the supposed shortage of gasoline encouraged the exploitation of oil shale deposits for transportation fuels. Many companies were formed to develop the oil shale deposits of the Green River Formation in the western United States, especially in Colorado. Oil placer claims were filed by the thousand on public lands. The Mineral Leasing Act of 1920 removed oil shale and certain other fossil fuels and minerals on public lands administered by the Federal Government from the status of locatable to leaseable minerals. Under this Act, the ownership of the public mineral lands is retained by the Federal Government and the mineral, e.g. oil shale, is made available for development by private industry under the terms of a mineral lease.

Figure 3-2 Oil shale mined from deposits in Brazil, China, Estonia, Germany, Russia and Scotland, 1880-2000
Source: USGS



Several oil shale leases on Federal lands in Colorado and Utah were issued to private companies in the 1970s. Large-scale mine facilities were developed on the properties and experimental underground 'modified in-situ' retorting was carried out on one of the lease tracts. However, all work eventually ceased and the leases were relinquished to the Federal Government. Unocal operated the last large-scale experimental mining and retorting facility in the western United States from 1980 until its closure in 1991. The company produced 4.5 million barrels of oil from oil shale averaging 34 gallons of shale oil per ton of rock over the life of the project. After many years in the doldrums, interest in oil shale was rekindled in 2004 (see the Country Note on the USA).

The tonnages mined in six oil shale producing countries for the period 1880 to 2000 are shown in Fig. 3-2. By the late 1930s, total yearly production of oil shale for these six countries had risen to over 5 million tonnes. Although production fell in the 1940s during World War II, it continued to rise for the next 35 years, peaking in 1979-1980 when in excess of 46 million tonnes of oil shale per year was mined, two-thirds of which was in Estonia. Assuming an average shale oil content of 100 l/tonne, 46 million tonnes of oil shale would be equivalent to 4.3 million tonnes of shale oil. Of interest is a secondary period of high production reached by China in 1958-1960 when as much as 24 million tonnes of oil shale per year were mined at Fushun.

The oil shale industry as represented by the six countries in Fig. 3-2 maintained a combined yearly production of oil shale in excess of 30 million tonnes from 1963 to 1992. From the peak year of 1981, yearly production of oil shale steadily declined to a low of about 15 million tonnes in 1999. Most of this decline is due to the gradual downsizing of the Estonian oil shale industry. This decline was not due to diminishing supplies of oil shale but to the fact that oil shale could not compete economically with petroleum as a fossil energy resource. On the contrary, the potential oil shale resources of the world have barely been touched.

Oil Shale Resources

Although information about many oil shale deposits is rudimentary and much exploratory drilling and analytical work needs to be done, the potential resources of oil shale in the world are enormous. An evaluation of world oil shale resources is made difficult because of the numerous ways by which the resources are assessed. Gravimetric, volumetric, and heating values have all been used to determine the oil shale grade. For example, oil shale grade is expressed in litres per tonne or gallons per short

By far the largest known deposit is the Green River oil shale in the western United States, which contains a total estimated resource of nearly 1.5 trillion barrels.

ton, weight percent shale oil, kilocalories of energy per kilogram of oil shale or Btu, and others. If the grade of oil shale is given in volumetric measure (litres of shale oil per tonne), the density of the oil must be known to convert litres to tonnes of shale oil.

By-products can add considerable value to some oil shale deposits. Uranium, vanadium, zinc, alumina, phosphate, sodium carbonate minerals, ammonium sulphate, and sulphur add potential value to some deposits. The spent shale obtained from retorting may also find use in the construction industry as cement. Germany and China have used oil shale as a source of cement. Other potential by-products from oil shale include specialty carbon fibres, adsorbent carbons, carbon black, bricks, construction and decorative building blocks, soil additives, fertilisers, rock wool insulating materials, and glass. Many of these by-products are still in the experimental stage, but the economic potential for their manufacture seems large.

Many oil shale resources have been little explored and much exploratory drilling needs to be done to determine their potential. Some deposits have been fairly well explored by drilling and analyses. These include the Green River oil shale in western United States, the Tertiary deposits in Queensland, Australia, the deposits in Sweden and Estonia, the El-Lajjun deposit in Jordan, perhaps those in France, Germany and Brazil, and possibly several in Russia. It can be assumed that the deposits will yield at least 40 litres of shale oil per tonne of shale by Fischer assay. The remaining deposits are poorly known and further study and analysis are needed to adequately determine their resource potential.

By far the largest known deposit is the Green River oil shale in the western United States, which contains a total estimated resource of nearly 1.5 trillion barrels. In Colorado alone, the total resource reaches 1 trillion barrels of oil. The Devonian black shales of the eastern United States are estimated at 189 billion barrels. Other important deposits include those of Australia, Brazil, China, Estonia, Jordan, and Morocco.

The total world resource of shale oil is estimated at 2.8 trillion barrels. This figure is considered to be conservative in view of the fact that oil shale resources of some countries are not reported and other deposits have not been fully investigated. On the other hand, several deposits, such as those of the Heath and Phosphoria Formations and portions of the Swedish alum oil shale, have been degraded by geothermal heating. Therefore, the resources reported for such deposits are probably too high and somewhat misleading.

Recoverable Resources

The amount of shale oil that can be recovered from a given deposit depends upon many factors. As alluded to above, geothermal heating, or other factors, may have degraded some or all of a deposit, so that the amount of recoverable energy may be significantly decreased. Some deposits or portions thereof, such as large areas of the Devonian black shales in the eastern United States, may be too deeply buried to mine economically in the foreseeable future. Surface land uses may greatly restrict the availability of some oil shale deposits for development, especially those in the industrial western countries. The obvious need today is new and improved methods for the economic recovery of energy and by-products from oil shale. The bottom line in developing a large oil shale industry will be governed by the price of petroleum-based crude oil.

The high petroleum price of recent times has prompted governments around the world to re-examine their energy supplies and to consider national security issues. Whereas at one time an indigenous energy resource such as oil shale would have been left undeveloped, it is now becoming attractive and feasible to further R&D programmes.

The current high interest in oil shale is evidenced by the fact that in October 2006, some 270 participants, representing 20 countries, were registered for an oil shale symposium organised by the Colorado School of Mines (CSM). During the proceedings the CSM extended an offer of help to the development of oil shale resources around the world. It was noted that whilst the opportunities exist, the technological and environmental challenges of a zero emission policy are great.

John R. Dyni
US Geological Survey

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TABLES

Table 3-1 Shale oil: resources and production at end-2005

	In-place shale oil resources (million barrels)	In-place shale oil resources (million tonnes)	Production in 2005 (thousand tonnes [oil])
Egypt (Arab Rep.)	5 700	816	
Congo (Democratic Rep.)	100 000	14 310	
Madagascar	32	5	
Morocco	53 381	8 167	
South Africa	130	19	
Total Africa	**159 243**	**23 317**	
Canada	15 241	2 192	
United States of America	2 085 228	301 566	
Total North America	**2 100 469**	**303 758**	
Argentina	400	57	
Brazil	82 000	11 734	159
Chile	21	3	
Total South America	**82 421**	**11 794**	**159**
Armenia	305	44	
China	16 000	2 290	180
Kazakhstan	2 837	400	
Mongolia	294	42	
Myanmar (Burma)	2 000	286	
Thailand	6 400	916	
Turkey	1 985	284	
Turkmenistan	7 687	1 100	
Uzbekistan	8 386	1 200	
Total Asia	**45 894**	**6 562**	**180**
Austria	8	1	
Belarus	6 988	1 000	
Bulgaria	125	18	
Estonia	16 286	2 494	345
France	7 000	1 002	
Germany	2 000	286	
Hungary	56	8	
Italy	73 000	10 446	
Luxembourg	675	97	
Poland	48	7	
Russian Federation	247 883	35 470	

Table 3-1 Shale oil: resources and production at end-2005

	In-place shale oil resources (million barrels)	In-place shale oil resources (million tonnes)	Production in 2005 (thousand tonnes [oil])
Spain	280	40	
Sweden	6 114	875	
Ukraine	4 193	600	
United Kingdom	3 500	501	
Total Europe	**368 156**	**52 845**	**345**
Israel	4 000	550	
Jordan	34 172	5 242	
Total Middle East	**38 172**	**5 792**	
Australia	31 729	4 531	
New Zealand	19	3	
Total Oceania	**31 748**	**4 534**	
TOTAL WORLD	**2 826 103**	**408 602**	**684**

Notes:

1. The figures for Turkmenistan refer to the Amu-Darya Basin, which also extends into Uzbekistan
2. Source: J.R. Dyni, U.S. Geological Survey

COUNTRY NOTES

The following Country Notes on Oil Shale have been compiled by the Editors, drawing upon a wide variety of material, including papers authored by J.R. Dyni of the USGS, papers presented at the Symposium on Oil Shale in Tallinn, Estonia, November 2002, papers presented at the 26th Oil Shale Symposium in Golden, Colorado, October 2006, national and international publications, and direct communications with oil shale experts.

Australia

The total demonstrated oil shale resource is estimated to be in the region of 58 billion tonnes, of which about 24 billion barrels of oil is recoverable. The deposits are spread through the eastern and southern states of the country (Queensland, New South Wales, South Australia, Victoria and Tasmania), although it is the eastern Queensland deposits that have the best potential for economic development.

Production from oil shale deposits in southeastern Australia began in the 1860s, coming to an end in 1952 when government funding ceased. Between 1865 and 1952 some 4 million tonnes of oil shale were processed.

During the 1970s and early 1980s a modern exploration programme was undertaken by two Australian companies, Southern Pacific Petroleum N.L. and Central Pacific Minerals N.L. (SPP/CPM). The aim was to find high-quality oil shale deposits amenable to open-pit mining operations in areas near infrastructure and deepwater ports. The programme was successful in finding a number of silica-based oil shale deposits of commercial significance along the coast of Queensland. Ten deposits clustered in an area north of Brisbane were investigated and found to have an oil shale resource in excess of 20 billion barrels (based on a cutoff grade of 50 l/t at 0% moisture), which could support production of more than 1 million barrels a day.

Between 1995 and February 2002 the Stuart Deposit (located near Gladstone) was developed, firstly by a joint venture between SPP/CPM and Suncor Energy Inc. of Canada and then by SPP/CPM, following its purchase of Suncor's interest. Further corporate restructuring took place when SPP became the holding company and CPM was delisted from the Australian stock exchange.

The Stuart project (found to have a total in-situ shale oil resource of 2.6 billion barrels and a capacity to produce more than 200 000 b/d) and incorporating the Alberta-Taciuk Processor (ATP) retort technology had three stages: The Stage 1 demonstration plant (producing a relatively light 42^{o} API gravity crude with 0.4 wt% sulphur and 1.0 wt% nitrogen) was constructed between 1997 and 1999 and produced over 500 000 barrels. The plant was designed to process 6 000 tonnes per stream day of run-of-mine (wet shale) to produce 4 500 bpsd of shale oil products. Stage 2 was to be scaled up by a factor of 4 to a commercial-sized module processing 23 500 tpsd and producing 15 500 bpsd oil products. It was envisaged that multiple commercial ATP units would come on stream during 2010-2013 processing up to 380 000 tpsd and producing up to 200 000 bpsd of oil products for a period in excess of 30 years.

To meet the needs of the market, the raw oil required further processing which resulted in ultra low-sulphur naphtha and light fuel oil. Shale oil has been certified as a feedstock for jet fuel production by the world's leading accreditation agencies and a long-term contract for the sale of naphtha to Mobil Oil Australia was in place. The light fuel oil was shipped to Singapore and sold into the fuel oil blending market.

Having committed itself to ensuring that the Stuart oil shale project had a sustainable development, SPP put various schemes into operation to achieve its stated environmental goals. One in particular launched in 1998 was a reforestation carbon dioxide sink. Some 250 000 trees were planted on deforested lands in Central Queensland. In September 2000, the first carbon trade in Queensland was announced. It was between SPP and the state government and was based on the reforestation trials.

In February 2004 Queensland Energy Resources Ltd. (QERL) acquired the oil shale assets of SPP and ran final plant trials at the demonstration facility. However, no production ensued and the Environmental Protection Agency regulated operations until the plant was closed in mid-2004. The facility is now on ‘care-and-maintenance in an operable condition’.

QERL continues to assess the possibilities for the future commercial operation of the Stuart project.

Brazil

The oil shale resource base is one of the largest in the world and was first exploited in 1884 in the State of Bahia. In 1935 shale oil was produced at a small plant in São Mateus do Sul in the State of Paraná and in 1950, following government support, a plant capable of producing 10 000 b/d shale oil was proposed for Tremembé, São Paulo.

Following the formation of Petrobras in 1953, the company developed the Petrosix process for shale transformation. Operations are concentrated on the reservoir of São Mateus do Sul, where the ore is found in two layers: the upper layer of shale (6.4 m thick), with an oil content of 6.4%, and the lower 3.2 m layer with an oil content of 9.1%. The company brought a pilot plant (8 inch internal diameter retort) into operation in 1982, its purpose being for oil shale characterisation, retorting tests and developing data for economic evaluation of new commercial plants. A 6 ft (internal diameter) retort demonstration plant followed in 1984 and was used for the optimisation of the Petrosix technology.

A 2 200 (nominal) tonnes per day, 18 ft (internal diameter) semi-works retort (the Iratí Profile Plant), originally brought on line in 1972, began operating on a limited commercial scale in 1981 and a further commercial plant - the 36 ft (internal diameter) Industrial Module retort - was brought into service in December 1991. Together the two commercial plants have a process capacity of some 7 800 tonnes of bituminous shale daily. The retort process (Petrosix) where the shale undergoes pyrolysis yields a nominal daily output of 3 870 barrels of shale oil, 120 tonnes of fuel gas, 45 tonnes of liquefied shale gas and 75 tonnes of sulphur. Actual daily output in 2005 was 3 040 barrels of shale oil, 80 tonnes of fuel gas, 31 tonnes of liquefied shale gas and 49 tonnes of sulphur.

The Ministry of Mines and Energy quotes end-1999 shale oil reserves as 445.1 million m^3 measured/indicated/inventoried and 9 402 million m^3 inferred/estimated, with shale gas reserves as 111 billion m^3 measured/indicated/inventoried and 2 353 billion m^3 inferred/estimated.

Canada

Oil shales occur throughout the country, with as many as 19 deposits having been identified. However, the majority of the in-place shale oil resources remain poorly known. The most explored deposits are those in the provinces of Nova Scotia and New Brunswick. Of the areas in Nova Scotia known to contain oil shales, development has been attempted at two - Stellarton and Antigonish. Mining took place at Stellarton from 1852 to 1859 and 1929 to 1930 and at Antigonish around 1865. The Stellarton Basin is estimated to hold some 825 million tonnes of oil shale, with an in-situ oil content of 168 million barrels. The Antigonish Basin has the second largest oil shale resource in Nova Scotia, with an estimated 738 million tonnes of shale and 76 million barrels of oil in situ.

Investigations into retorting and co-combustion (with coal for power generation) of Albert Mines shale (New Brunswick) have been conducted, including some experimental processing in 1988 at the Petrobras plant in Brazil. Interest has been shown in the New Brunswick deposits for the potential they might offer to reduce sulphur emissions by co-combustion of carbonate-rich shale residue with high-sulphur coal in power stations.

China

Between 2004 and 2006 China undertook its first national oil shale evaluation, which confirmed that the resource was both widespread and vast. According to the evaluation, it has been estimated that a total oil shale resource of some 720 billion tonnes is located across 22 provinces, 47 basins and 80 deposits. The shale oil resource has been estimated at some 48 billion tonnes.

Proved reserves of oil shale are estimated to be in the region of 36 billion tonnes.The major deposits are in Fushun in the north-eastern province of Liaoning, with a reserve of 3.6 billion tonnes and a Fischer Assay of 6%; Maoming in Guangdong, with 4.1 billion tonnes and 7%; Huadian in Jilin, with 0.3 billion tonnes and 10%; Longkow in Shandong with 0.1 billion tonnes and 14% and Nong An in Jilin with 16 billion tonnes and 4.5%.

The city of Fushun is known as the Chinese 'capital of coal'. Within the Fushun coalfield the West Open Pit mine is the largest operation of coal mining and is where, above the coal layer, oil shale from the Tertiary Formation is mined as a by-product.

The commercial extraction of oil shale and the operation of heating retorts for processing the oil shale were developed in Fushun between 1920 and 1930. After World War II, Refinery No. 1 had 200 retorts, each with a daily throughput of 100-200 tonnes of oil shale. It continued to operate and was joined by Refinery No. 2, restored in 1954. In Refinery No. 3 shale oil was hydrotreated for producing light liquid fuels. Shale oil was also open-pit mined in Maoming and 64 retorts were put into operation there in the 1960s.

At the beginning of the 1960s, 266 retorts were operating in Fushun's Refinery Nos. 1 and 2 and production peaked at about 23 million tonnes of oil shale (about 780 000 tonnes of shale oil). However, during the 1980s production had dropped to about 300 000 tonnes of shale oil and at the beginning of the 1990s the availability of much cheaper crude oil had led to the Maoming operation and Fushun Refinery Nos. 1 and 2 being shut down.

A new facility - the Fushun Oil Shale Retorting Plant - came into operation under the management of the Fushun Bureau of Mines. It at first consisted of 60 retorts producing 60 000 tonnes per year of shale oil to be sold as fuel oil, with carbon black as a by-product. By 2005 the total number of retorts stood at 120, each with a daily capacity of 100 tonnes of oil shale. In that year 180 000 tonnes of shale oil were produced. In 2006 it was expected that Fushun would again be expanded and operate 140 retorts. In addition to fuel oil some of the surplus retort gas with low heating value is used to produce steam and power. The shale ash is utilised in a 90 000 tonne/yr cement factory and a brick factory with an output of 60 million bricks per year.

Owing to high crude oil prices and favourable economic factors it is planned to further increase production capacity and a project to build an ATP retort capable of processing 6 000 tonnes per day is planned.

The production of oil shale has long been a by-product of Chinese coal mining. In the Longkow mining area the Bureau of Mines has a project to build a plant designed to process 2 million tonnes of oil shale, producing 200 000 tonnes of shale oil. A feasibility study has been approved by the Shandong Provincial Development Committee and following the utilisation of Fushun-type retorting to begin with, it is planned to use fluidised-bed combustion for producing power and ash suitable for building products.

A similar project is planned for Huadian in Jilin Province but with Petrosix technology being used. A prefeasibility study was approved by the China National Development and Reform Commission in late-2003 and the scheme is now at the feasibility stage.

It is planned to utilise oil shale once again in the Maoming retort in a fluidised-bed combustion process for the production of power.

China's high level of oil imports is influencing the country to further consider the development of its oil shale resource. It is possible that reserves in Uromqi Xinjiang, Yongden Gansu, Yilan, Heilongjiang etc will be utilised in the near future.

China possesses a wealth of knowledge regarding oil shale and the Petroleum University is assisting with a feasibility study on the Khoot oil shale deposit in Mongolia.

In 2005 the China National Oil Shale Association was established.

Egypt (Arab Republic)

Oil shale was discovered during the 1940s as a result of oil rocks self-igniting whilst phosphate mining was taking place. The phosphate beds in question lie adjacent to the Red Sea in the Safaga-Quseir area of the Eastern Desert. Analysis was at first undertaken in the Soviet Union in 1958 and was followed by further research in Berlin in the late 1970s. This latter work concentrated on the phosphate belt in the Eastern Desert, the Nile Valley and the southern Western Desert. The results showed that the Red Sea area was estimated to have about 4.5 billion barrels of in-place shale oil and that in the Western Desert, the Abu Tartour area contained about 1.2 billion barrels.

The studies concluded that the oil shale rocks in the Red Sea area were only accessible by underground mining methods and would be uneconomic for oil and gas extraction. However, the Abu Tartour rocks could be extracted whilst mining for phosphates and then utilised for power production for use in the mines. Additionally, although in both areas power could be generated for the in-place cement industry, the nature of the shale as a raw material would not be conducive to the manufacture of high-quality cement.

In view of the depletion of Egyptian fossil fuel reserves, a research project was implemented during 1994-1998 on the 'Availability of Oil Shale in Egypt and its Potential Use in Power Generation'. The project concluded that the burning of oil shale and its use as fuel for power production was feasible, but only became economic when heavy fuel oil and coal prices rose to significantly higher levels. Many recommendations of a technological and environmental nature were made and economic studies continue. A 20 MW oil shale pilot plant for power generation in Quseir was recommended as part of a first step towards the exploitation of Egyptian oil shale.

Estonia

Oil shale was first scientifically researched in the 18th century. In 1838 work was undertaken to establish an open-cast pit near the town of Rakvere and an attempt was made to obtain oil by distillation. Although it was concluded that the rock could be used as solid fuel and, after processing, as liquid or gaseous fuel, the 'kukersite' (derived from the name of the locality) was not exploited until the fuel shortages created by World War I began to impact.

The Baltic Oil Shale Basin is situated near the north-western boundary of the East European Platform. The Estonia and Tapa deposits are both situated in the west of the Basin, the former being the largest and highest-quality deposit within the Basin.

Since 1916 oil shale has had an enormous influence on the energy economy, particularly during the period of Soviet rule and then under the re-established Estonian Republic. At a very early stage, an oil shale development programme declared that kukersite could be used directly as a fuel in the domestic, industrial or transport sectors. Moreover, it was easily mined and could be even more effective as a combustible fuel in power plants or for oil distillation. Additionally kukersite ash could be used in the cement and brick-making industries.

Permanent mining began in 1918 and has continued until the present day, with capacity (both underground mining and open-cast) increasing as demand rose. By 1955 oil shale output had reached 7 million tonnes and was mainly used as power station/chemical plant fuel and in the production of cement. The opening of the 1 400 MW Balti Power Station in 1965 followed, in 1973, by the 1 600 MW Eesti Power Station again boosted production and by 1980 (the year of maximum output) the figure had risen to 31.35 million tonnes.

In 1981, the opening of a nuclear power station in the Leningrad district of Russia signalled the beginning of the decline in Estonian oil shale production. No longer were vast quantities required for power generation and the export of electricity. The decline lasted until 1995, since when production levels have varied but generally are less than half of those of the early 1980s.

The total Estonian in-place shale oil resource is currently estimated to be in the region of 16 billion barrels and at the present time continues to play a dominant role in the country's energy balance. However, many factors: economic, political and environmental are all having an effect.

In the years following independence, the oil shale industry was privatised and is now open to the forces of free market competition; production of oil shale has been shown to be economically viable up to a crude oil price of US$ 30 but with prices in excess of this level, new mining projects have become feasible; the country’s accession to the European Union has brought compliance with many directives, especially the emissions trading directive. Estonia has ratified the various climate change and pollution control protocols of recent years but must increasingly address the air and water pollution problems that nearly a century of oil shale mining has brought. Many investment programmes have been launched in an attempt to reduce the environmental effects of oil shale.

In 2005 14.6 million tonnes of oil shale were produced, among them the billionth tonne. Imports amounted to 0.2 million tonnes, 10.9 million tonnes were used for electricity generation, 0.7 for heat generation and 2.8

million tonnes were processed for shale oil and coke production. Production of shale oil was 345 000 tonnes, 222 000 tonnes were exported, 8 000 tonnes were utilised for electricity generation and 98 000 for heat generation.

The historical ratio of underground mining to open-cast (approximately 50:50) is tending to move away from open-cast production as the bed depths increase – the exhausted open-cast areas are gradually being recultivated and reforested. The Government has decreed that the share of renewables in electricity production will increase to 5.1% by 2012. Additionally, both the Long-term Development Plan for the Estonian Fuel and Energy Sector and the Estonia Forestry Development Programme 2001-2010 both state that the share of biofuels will increase. However, although the country possesses low-pollution peat and biofuels resources, they are limited and therefore oil shale is likely to remain central to the energy balance in the next decade.

Ethiopia

The existence of oil shale deposits in Ethiopia has been known since the 1950s. Although surveys were undertaken, no projects were proceeded with owing to high mining costs and lack of funding.

The resource, estimated to be 3.89 billion tonnes, in the northern province of Tigray is considered to be suitable for open-cast mining.

France

Oil shale was irregularly exploited in France between 1840 and 1957 but at its highest (1950), output only reached 0.5 million tonnes per year of shale. During its 118 year life, the Government imposed taxes and duties on foreign oil, thus preserving the indigenous industry.

In 1978 it was estimated that the in-place shale oil resources amounted to 7 billion barrels.

Germany

The German oil shale industry was developed in the middle of the 19^{th} century and during the 1930s and 1940s the development of retorted oil contributed to the depleted fuel supplies during World War II.

Today the only active plant is located in Dotternhausen in southern Germany, where Rohrbach Zement began using oil shale in the 1930s. At the beginning of 2004, Holcim, a Swiss cement and aggregates company acquired Rohrbach Zement. The oil shale from this area has a low energy content, a low oil yield and a high ash content but by using a complex process the complete utilisation of both the oil shale energy and all its minerals can be accomplished and incorporated into the manufacture of cement and other hydraulic binding agents. A small part of the oil shale is directly used in a rotary kiln for cement clinker production as fuel and raw material. Most of the oil shale, however, is burnt in fluidised-bed units to produce a hydraulic mineral cement component while the heat of this process is used simultaneously to produce electricity.

A minimal quantity of oil shale is produced for use at Holcim's Dotternhausen cement plant. In 2005 and 2006 production amounted to 284 000 and 320 000 tonnes respectively.

In 1965 it was estimated that Germany's in-place shale oil resources amounted to 2 billion barrels.

India

Although oil shale, in association with coal and also oil, is known to exist in the far northeastern regions of Assam and Arunachal Pradesh, the extent of the resource and its quality have not yet been determined.

Currently oil shale, recovered with coal during the mining process, is discarded as a waste product. However, the Indian Directorate General of Hydrocarbons has initiated a project designed to assess the reserve and its development.

Indonesia

Faced with declining reserves of oil and gas, Indonesia has accelerated its research into identifying, and possibly utilising, its oil shale resources.

The Center for Geo Resources is currently engaged on surveying and preparing an inventory of occurrences. To date, three main prospective oil shale areas have been found, two on the island of Sumatera and one on Sulawesi.

Israel

Sizeable deposits of oil shale have been discovered in various parts of Israel, with the principal resources located in the north of the Negev desert. Estimates of the theoretical reserves total some 300 billion tonnes, of which those considered to be open-pit mineable are put at *only* a few billion tonnes. The largest deposit (Rotem Yamin) has shale beds with a thickness of 35-80 m, yielding 60-71 l of oil per tonne. Generally speaking, Israeli oil shales are relatively low in heating value and oil yield, and high in moisture, carbonate, and sulphur content, compared with other major deposits. Following tests in a 0.1 MW pilot plant (1982-1986), a 1 MW demonstration fluidised-bed pilot plant was established in 1989. In operation since 1990, the generated energy is sold to the Israeli Electric Corporation, the low-pressure steam to an industrial complex and a considerable quantity of the resulting ash used to make products such as cat litter which is exported to Europe.

Although during the early 1990s proposals for shale oil extraction were put forward, the crude oil price was not high enough to justify financial viability. With the current higher global crude oil price, the project has been seen to be economically possible.

During 2006, A.F.S.K. Hom-Tov, an Israeli company presented a scheme to the Ministry of National Infrastructures for the manufacture of synthetic oil from oil shale. The method would entail combining bitumen (from the Ashdod refinery, 80 km north of the proposed plant at Mishor Rotem in the Negev Desert) with the shale prior to processing in a catalytic converter. It has been suggested that the resultant oil, totalling up to 3 million tonnes/yr, could be piped back to Ashdod for refining. Additionally, the remaining shale rock, containing some residual fuel, could be utilised in a new power plant in the south of the country.

Oil shale is already being mined by companies accessing the phosphate reserves underlying the rock.

Whilst the Government is encouraging development of the oil shale resource, particularly in-situ underground techniques, it is mindful of the environmental concerns.

Jordan

There are about 24 known occurrences, which result in Jordan having an extremely large proven and exploitable oil shale resource. Geological surveys indicate that the existing shale reserves cover more than 60% of the country and amount to in excess of 50 billion tonnes.

The eight most important deposits are located in west-central Jordan and of these, El Lajjun, Sultani, and the Jurf Ed-Darawish have been the most extensively explored. They are all classified as shallow and most are suitable for open-cast mining, albeit some are underlain by phosphate beds. One more deposit, Yarmouk, located close to the northern border is thought to extend into Syria and may prove to be exceptionally large, both in area and thickness. Reaching some 400 m in thickness, it would only be exploitable by underground mining.

The naturally bituminous marls of Jordan are generally of quite good quality. The oil content and calorific value vary quite widely between deposits but research has shown that 20-30% of the original thermal content remains in the retorted residue, thus providing a source of fuel for the production of heat or electricity. Additionally, it has been shown that the levels of sulphur and mineral content would not cause technological or environmental problems.

During the past two decades the Government has undertaken a number of feasibility studies and test programmes. These have been carried out in co-operation with companies from Germany, China, Russia, Canada and Switzerland. They were all intended to demonstrate utilisation through either direct burning or retorting. All tests proved that burning Jordanian oil shale is very stable, emission levels are low and carbon burn-out is high. Furthermore, research on catalytic gasification was undertaken in the FSU, with positive results. Solvent extraction of organic matter was the subject of a joint study by the Jordanian Natural Resources Authority and the National Energy Research Center.

The eventual exploitation of Jordan's fuel resource to produce liquid fuels and/or electricity, together with chemicals and building materials, would be favoured by three factors - the high organic matter content of Jordanian oil shale, the suitability of the deposits for surface-mining and their location - away from centres of population but having good transport links to potential consumers (i.e. phosphate mines, potash and cement works).

In recent years the price of crude oil has not been high enough to justify the financial commitment of developing Jordanian oil shale. The National Resources Agency proposed that it should continue to monitor both technological advances and the economic aspects of prospective projects. However, the Government now considers that owing to the rapid increase in demand for electricity, the prospective grid connections between countries in the region and significantly higher oil prices, the required investment is not only becoming feasible but should be pursued through joint ventures and BOT projects.

The Ministry of Energy and Mineral Resources (MEMR) stated in its 2005 Annual Report that a study on the future strategy of the nascent industry would be financed by the US Trade Development Agency. The 2006 study was due to address the question of the shale oil being utilised directly for electricity generation or sent for distillation.

In November 2006 Eesti Energia of Estonia announced that the company had been awarded the right to explore 300 million tonnes of the El Lajjun reserve. A study to establish whether the construction of a shale oil facility would be feasible and mutually beneficial is estimated to take 18 months.

Early in 2007, it was reported that Petrobras of Brazil had signed an MOU with the MEMR to study the economic viability of using the company's Petrosix process on the oil shale of the Attarat Umm Ghudran deposit.

Kazakhstan

At the beginning of the 1960s successful experimentation was carried out on a sample of Kazakhstan's oil shale in the former Soviet Republic of Estonia. Both domestic gas and shale oil were produced. It was found that the resultant shale oil had a low-enough sulphur content for the production of high-quality liquid fuels.

Beginning in early 1998 and lasting until end-2001, a team funded by INTAS (an independent, international association formed by the European Community to preserve and promote scientific co-operation with the newly independent states) undertook a project aimed at completely reevaluating Kazakhstan's oil shales. The resultant report testified that Kazakhstan's oil shale resources could sustain the production of various chemical and power-generating fuel products.

The research undertaken concluded that the occurrence of oil shale is widespread, the most important deposits having been identified in western (the Cis-Urals group of deposits) and eastern (the Kenderlyk deposit) Kazakhstan.

Further deposits have been discovered in both the southern region (Baikhozha and the lower Ili river basin) and the central region (the Shubarkol deposit).

In excess of 10 deposits have been studied: the Kenderlyk Field has been revealed as the largest (in the region of 4 billion tonnes) and has undergone the greatest investigation. However, studies on the Cis-Urals group and the Baikhozha deposit have shown that they have important concentrations of rare elements (rhenium and selenium), providing all these deposits with promising prospects for future industrial exploitation.

The in-place shale oil resources in Kazakhstan have been estimated to be in the region of 2.8 billion barrels. Moreover, many of the deposits occur in conjunction with hard and brown coal accumulations which, if simultaneously mined, could increase the profitability of the coal production industry whilst helping to establish a shale-processing industry.

The recommendations made to INTAS were that collaboration between the project's participants should continue and further research undertaken on a commercial basis with interested parties, as a precursor to the establishment of such an industry.

Mongolia

Mongolia possesses large mineral deposits which, owing to the country's political isolation during most of the 20th century, remain largely undeveloped. Some mining operations were established prior to 1989 with the help of the Soviet Union and Eastern European countries but following the breakup of the USSR, Mongolia's move to a free economy and the Minerals Law being passed in 1997, the potential is being recognised.

Numbered amongst the indigenous minerals are oil shale deposits from the Lower Cretaceous Dsunbayan Group, located in the east of the country. Exploration and investigation of the deposits began as long ago as 1930 but it was only during the 1990s and with the help of Japanese organisations that detailed analyses began. Twenty six deposits were studied and found to be associated with coal measures. Historically, Mongolia's coal has been mined as a source of energy, with the shale being left untouched. However, the study ascertained that the oil shales are 'excellent' potential petroleum source rocks, particularly the Eidemt deposit.

During 2004, Narantuul Trade Company, the owner of the Eidemt deposit was investigating the possibilities of developing the field's potential with the aid of international cooperation.

It was reported in late-2006 that China University of Petroleum had signed a contract to undertake a feasibility study on the Khoot oil shale deposit.

Morocco

Exploitation of oil shale in Morocco occurred as long ago as 1939, when the Tangier deposit was the source of fuel for an 80 tonnes/day pilot plant which operated until 1945. A preliminary estimate of this resource has been put at some 2 billion barrels of oil in place.

During the 1960s two important deposits were located: Timahdit in the region of the Middle Atlas range of mountains (north central Morocco) and Tarfaya in the south west, along the Atlantic coast. The total resource has been estimated at 42 billion tonnes for the former and 80 billion tonnes for the latter. Oil in place has been estimated at 16.1 billion barrels for Timahdit and 22.7 billion barrels for Tarfaya.

Morocco's total resource is estimated at some 50 billion barrels in place, a level which ranks the country amongst the world leaders in respect of in-place shale oil.

During the 1970s and 1980s, the Office National des Hydrocarbures et des Mines (ONHYM), with the assistance of companies in the USA, Europe, Canada and Japan, undertook research and testing of more than 1 500 tonnes of Timahdit and 700 tonnes of Tarfaya oil shale. Within Morocco, some 2 500 metric tonnes of Timahdit oil shale were tested in an 80 tonne capacity pilot plant. In 1985-1986 the Moroccan experience led to ONHYM developing its own process called T^3, a semi-continuous surface retorting method based on the utilisation of two identical retorts operating in tandem according to two modes: retorting mode and cooling mode.

The technical and economic feasibility studies have resulted in Morocco acquiring a large amount of information – a database which can be used for future projects. With the current need to look at developing alternative sources of liquid fuels, the ONHYM has stated that any pilot plant should be followed by a demonstration phase during which the commercial evaluation of by-products should also be undertaken.

Nigeria

Research has shown that the southeastern region of Nigeria possesses a low-sulphur oil shale deposit. The reserve has been estimated to be of the order of 5.76 billion tonnes with a recoverable hydrocarbon reserve of 1.7 billion barrels.

Russian Federation

In excess of 80 oil shale deposits have been identified in Russia.

The deposits in the Volga-Petchyorsk province, although of reasonable thickness (ranging from 0.8 to 2.6 m), contain high levels of sulphur.

Extraction began in this area in the 1930s, with the oil shale being used to fuel two power plants, but the operation was abandoned owing to environmental pollution. However, most activity has centred on the Baltic Basin where the kukersite oil shale has been exploited for many years. In 2002 the Leningradslanets Oil Shale Mining Public Company produced 1.12 million tonnes. Following June 2003 all shale mined was delivered to the Estonian Baltic power station with the resultant electricity delivered to UES (Unified Energy System of Russia). However, production ceased at the

Leningradslanets Mine on 1 April 2005. It has been reported that the Russian-owned company, Renova, plans to build its own shale oil producing plant. Although design work has yet to begin, oil shale production restarted on 15 January 2007, with the 50 000 tonnes per month being stored.

Until 1998, the Slantsy electric power plant (located close to the Estonian border, 145 km from St Petersburg) was equipped with oil shale fired furnaces but in 1999 its 75 MW plant was converted to use natural gas. It continued to process oil shale for oil until June 2003, since when its main activities have been electrode coke annealing and the processing of coals and natural gas oil components.

In 1995 a small processing plant operated at Syzran with an input of less than 50 000 tonnes of shale per annum. Although the accompanying mine has now closed, a group of about 10 miners are producing in the region of 10 000 tonnes per year. Using the Syzran plant the oil shale is being processed for the manufacture of a pharmaceutical product. Investment is being sought for a new plant capable of processing 500 tonnes per day. The mine would be re-opened with the intention of perpetuating the production of pharmaceutical products. To this end a business plan has been issued.

Sweden

The huge shale resources underlying mainland Sweden are more correctly referred to as alum shale; black shale is found on two islands lying off the coast of south-eastern Sweden. The in-place shale oil resource is estimated to be 6.1 billion barrels.

The exploitation of alum shale began as early as 1637 when potassium aluminium sulphate (alum) was extracted for industrial purposes. By the end of the 19th century the alum shale was also being retorted in an effort to produce a hydrocarbon oil. Before and during World War II, Sweden derived oil from its alum shale, but this process had ceased by 1966, when alternative supplies of lower-priced petroleum were available; during the period 50 million tonnes of shale had been mined.

The Swedish alum shale has a high content of various metals including uranium, which was mined between 1950 and 1961. At that time the available uranium ore was of low grade but later higher-grade ore was found and 50 tonnes of uranium were produced per year between 1965 and 1969. Although the uranium resource is substantial, production ceased in 1989 when world prices fell and made the exploitation uneconomic.

Thailand

Some exploratory drilling by the Government was made as early as 1935 near Mae Sot in Tak Province on the Thai-Burmese border. The oil shale beds are relatively thin, underlying about 53 km^2 in the Mae Sot basin and structurally complicated by folding and faulting.

Another deposit at Li, Lampoon Province is small, estimated at 15 million tonnes of oil shale and yielding 50-171 l of oil per tonne.

Some 18.6 billion tonnes of oil shale, yielding an estimated 6.4 billion barrels of shale oil, have been identified in the Mae Sot Basin, but to date it has not been economic to exploit the deposits. In 2000 the Thai Government estimated that total proved recoverable reserves of shale oil were 810 million tonnes.

Turkey

Although oil shale deposits are known to exist over a wide area in middle and western Anatolia, they have received relatively little investigation. The total reserve of oil shale has been estimated to be in the region of 3-5 billion tonnes, with proved reserves put at 2.2 billion tonnes. Of this latter figure, the geologic reserve is put at 0.5 billion tonnes and the possible reserve at 1.7 billion tonnes. Four major deposits: Himmetoğlu, Seyitömer, Hatildağ and Beypazari have been studied in detail and found to vary quite widely in quality. Study is required of each individual reserve to establish the suitability of use. However, it is already considered that in general Turkish oil shale would be most profitably used to supplement coal or lignite as a power station fuel, rather than for the recovery of shale oil.

United States of America

It is estimated that nearly 74% of the world's potentially recoverable shale oil resources are concentrated in the USA. The largest of the deposits is found in the 42 700 km^2 Eocene Green River formation in north-western Colorado, north-eastern Utah and south-western Wyoming. The richest and most easily recoverable deposits are located in the Piceance Creek Basin in western Colorado and the Uinta Basin in eastern Utah. The shale oil can be extracted by surface and in-situ methods of retorting: depending upon the methods of mining and processing used, as much as one-third or more of this resource might be recoverable. There are also the Devonian-Mississippian black shales in the eastern United States. The Green River deposits account for 70% of US shale oil resources, the eastern black shales for 9%.

Oil distilled from shale was burnt and used horticulturally in the second half of the 19th century in Utah and Colorado but very little development occurred at that time. It was not until the early 1900s that the deposits were first studied in detail by the US Geological Survey and the Government established the Naval Petroleum and Oil Shale Reserves, which for much of the 20th century served as a contingency source of fuel for the nation's military. These properties were originally envisioned as a way to provide a reserve supply of oil to fuel US naval vessels.

Oil shale development had always been on a small scale but the project that was to represent the greatest development of the shale deposits was begun immediately after World War II in 1946 - the US Bureau of Mines established the Anvils Point oil shale demonstration project in Colorado. However, processing plants had been small and the cost of production high. It was not until the USA had become a net oil importer, together with the oil crises of 1973 and 1979, that interest in oil shale was reawakened. In the latter part of the 20th century military fuel needs changed and the strategic value of the shale reserves began to diminish.

In the 1970s ways to maximise domestic oil supplies were devised and the oil shale fields were opened up for commercial production. Oil companies led the investigations: leases were obtained and consolidated but one by one these organisations gave up their oil shale interests. Unocal was the last to do so in 1991.

Recoverable resources of shale oil from the marine black shales in the eastern United States were estimated in 1980 to exceed 400 billion barrels. These deposits differ significantly in chemical and mineralogical composition from Green River oil shale. Owing to its lower H:C ratio, the organic matter in eastern oil shale yields only about one-third as much oil as Green River oil shale, as determined by conventional Fischer assay analyses. However, when retorted in a hydrogen atmosphere, the oil yield of eastern oil shale increases by as much as 2.0-2.5 times the Fischer assay yield.

Green River oil shale contains abundant carbonate minerals including dolomite, nahcolite, and dawsonite. The latter two minerals have potential by-product value for their soda ash and alumina content, respectively. The eastern oil shales are low in carbonate content but contain notable quantities of metals, including uranium, vanadium, molybdenum, and others which could add significant by-product value to these deposits.

After many years of inactivity, interest was revived in the oil shale sector in 2004. A committee was formed by the Office of Naval Petroleum and Oil Shale Reserves and prepared two reports: 1) Strategic Significance of America's Oil Shale Resource, vol. I, Assessment of Strategic Issues and vol II, Oil Shale Resources, Technology and Economics and 2) America's Shale Oil, A Roadmap for Federal Decision Making.

The increasing price of petroleum has encouraged the Government to initiate steps toward the commercial development of the Green River oil shale deposits through the issuance of RD&D oil shale leases. In 2005, nominations for 160-acre tracts of public oil shale lands in Colorado and Wyoming were sought from private companies by the Bureau of Land Management (BLM). By September 2005, 19 applications for leases had been received - ten in Colorado, eight in Utah, and one in Wyoming. After a review of these nominations, five leases were granted in Colorado in late 2006; one lease in Utah received provisional approval (April 2007) and the Wyoming application was denied. All of the successful applicants for the Colorado leases propose to develop *in-situ* technologies for the recovery of shale oil, whereas the Utah lease applicant plans to use a surface retort. Industry interest in surface mining of oil shale in Colorado appears to be minimal, in view of the problems of possible large-scale environmental degradation of the oil shale lands.

The RD&D leases were issued for a term of 10 years with a possible five-year extension, providing that evidence of diligent pursuit of production of shale oil in commercial quantities is shown. If commercial production is achieved, a preference right for additional acreage of as much as 4 960 acres of oil shale lands may be granted. The RD&D leases include specific requirements of permitting, and monitoring and mitigation of environmental impacts.

Since 1996 Shell Frontier Oil & Gas has been developing a new technique for extracting the oil by in-situ heating of the rock in the Piceance Creek Basin. Shell's patented In-Situ Conversion Process (ICP), which is more environmentally benign and uses less water than conventional methods, involves heating the rock containing the kerogen until it yields a liquid hydrocarbon. In order to trap the oil prior to removal and refining, a barrier of ice between the heated rock and the surrounding area is created by the circulation of a chilled, compressed liquid.

In November 2006, Shell announced that the US BLM had awarded the company three leases on land in the Piceance Creek Basin to conduct further RD&D. This work will begin once the necessary State, air and water permits have been granted.

The estimated total resource of Green River oil shale in the three-state area amounts to about 1.5 trillion barrels of in-place shale oil. Although recoverable shale oil resources have been estimated to be as high as 800 billion barrels, no definitive study has yet been made to substantiate this figure.

By way of enhancing the publicly-available body of knowledge, the US Geological Survey is preparing a database with information taken from the Green River Formation prior to its closure in 1996 and is also acquiring new data and maps. The Office of Naval Petroleum and Oil Shale Reserves announced early in 2007 that the US could be producing oil from shale on a commercial basis in northwest Colorado by 2015.

4. Natural Bitumen and Extra-Heavy Oil

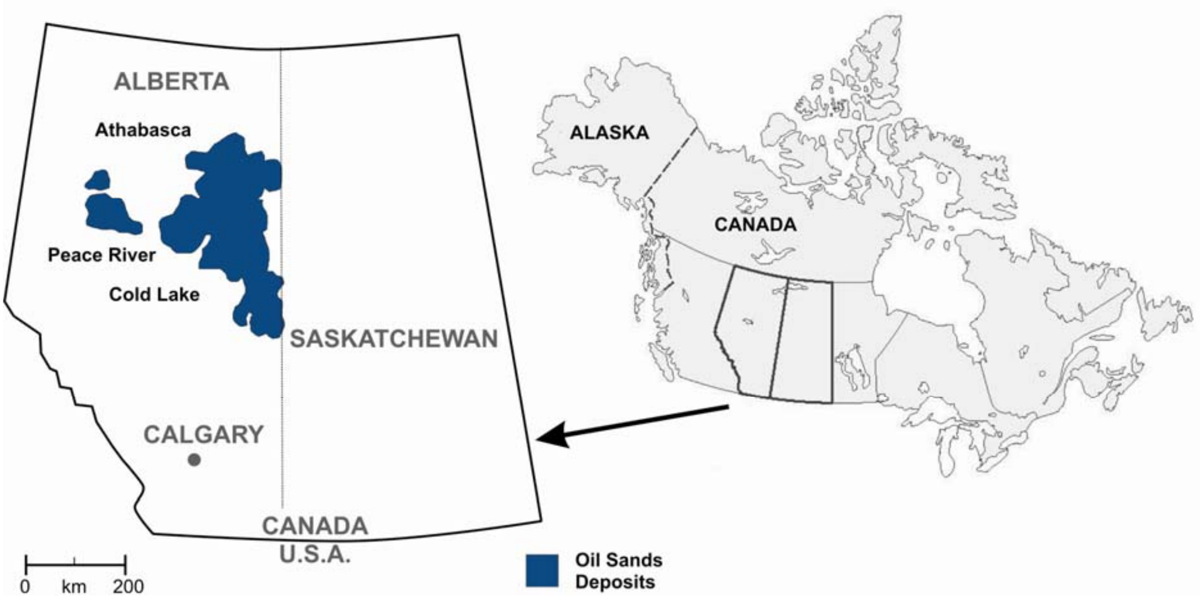
COMMENTARY

Introduction

Since 2005, oil price increases have greatly increased investment in the production of extra-heavy oil and natural bitumen (tar sands or oil sands) to supplement conventional oil supplies. These oils are characterised by their high viscosity, high density (low API gravity), and high concentrations of nitrogen, oxygen, sulphur, and heavy metals. Extra-heavy oil and natural bitumen are the remnants of very large volumes of conventional oils that have been generated and subsequently degraded, principally by bacterial action. Chemically and texturally, they resemble the residuum produced by refinery distillation of light oil. Although these viscous oils are much more costly to extract, transport and refine than conventional oils, production levels have increased to more than 1.6 million barrels per day, or just under 2% of world crude oil production.

The resource base of extra-heavy oil and natural bitumen is immense and can easily support a substantial expansion in production. This resource base can make a major contribution to oil supply, if it can be extracted and transformed into useable refinery feedstock at sufficiently high rates and at costs that are competitive with alternative resources. Technology must continue to be developed to address emerging challenges (both environmental and economic) in the market supply chain. (Definitions follow this Commentary).

Figure 4-1 Location of the oil sands deposits of Canada
Source: modified from McPhee and Ranger, 1998



Resource Quantities and Geographical Distribution

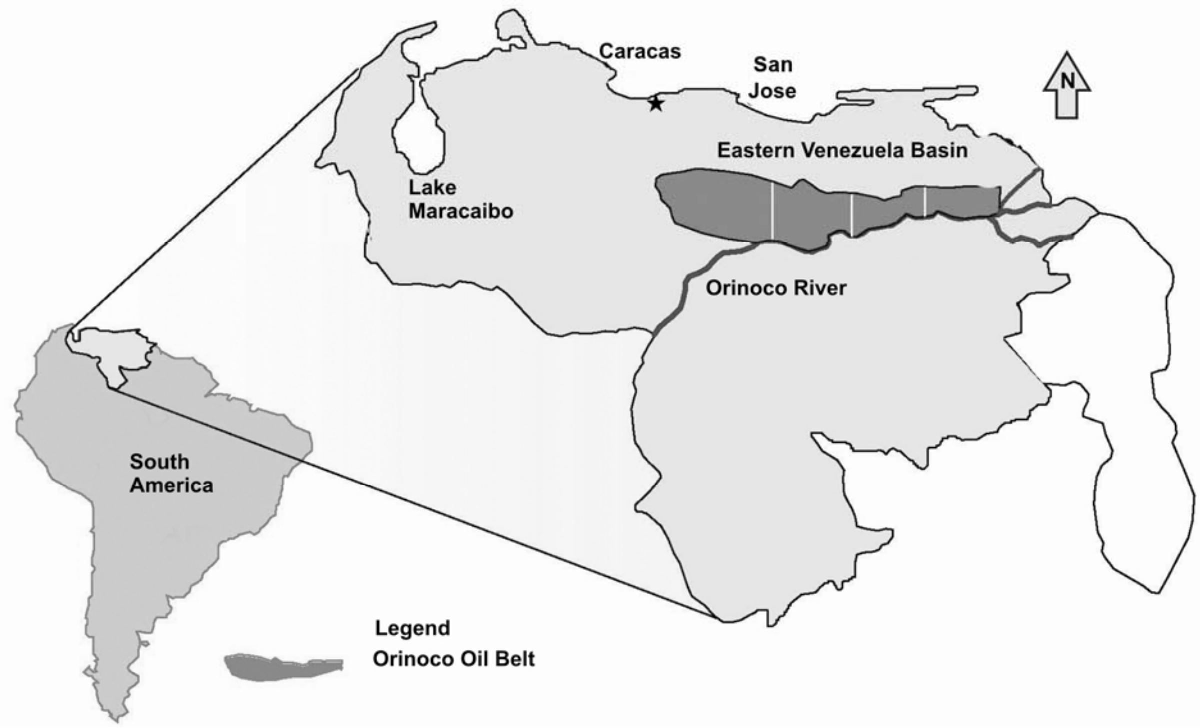
Resource quantities reported here are based upon a detailed review of the literature in conjunction with available databases, and are intended to suggest, rather than to define, the resource volumes that could someday be of commercial interest. Precise quantitative reserves and oil-in-place data on a reservoir basis are seldom available to the public, except in Canada. In cases where in-place resource estimates are not available, the in-place volume has been calculated from an estimate of the recoverable volumes, using assumed recovery factors. For deposits in clastic rocks the in-place volume was calculated as 10 times the original recoverable volumes (cumulative production plus an estimate of the remaining recoverable volume) and for carbonate reservoir accumulations the original oil in place was calculated as 20 times the estimated original recoverable volume. Geologic basin names used in the descriptions are standard and correspond to sedimentary basins shown on the map compiled by St. John, Bally, and Klemme (1984).

Natural bitumen

A summary of natural bitumen and extra-heavy oil resource quantities is given in Tables 4-1 and 4.2. Natural bitumen is reported in 586 deposits in 22 countries (Table 4-1). It occurs in clastic and carbonate reservoir rocks and commonly in small deposits at, or near, the earth's surface. Natural bitumen accumulations have been mined since antiquity for use as paving materials and sealants. In some places such deposits are extremely large, both in areal extent and in the resources they contain, most notably those in northern Alberta (Fig. 4-1), in the Western Canada Sedimentary Basin. The three Alberta oil sands areas, Athabasca, Peace River, and Cold Lake, together contain at least two-thirds of the world's discovered bitumen in place (1.7 trillion barrels) and are at the present the only bitumen deposits that are commercially exploited as sources of synthetic oil. More than one third of the crude oil produced in Canada currently comes from the Alberta natural bitumen deposits.

Outside of Canada, 359 natural bitumen deposits are reported in 21 other countries (Table 4-1). Although Kazakhstan and Russia have the largest amounts of bitumen after Canada, both countries also have large volumes of undeveloped, and undoubtedly less costly, conventional oil. In Kazakhstan, the largest number of bitumen deposits are located in the North Caspian Basin and many of Russia's bitumen deposits are located in the Timan-Pechora and Volga-Ural basins. The North

Figure 4-2 Location of the Orinoco Oil Belt in Venezuela
Source: modified from Layisse, 1999



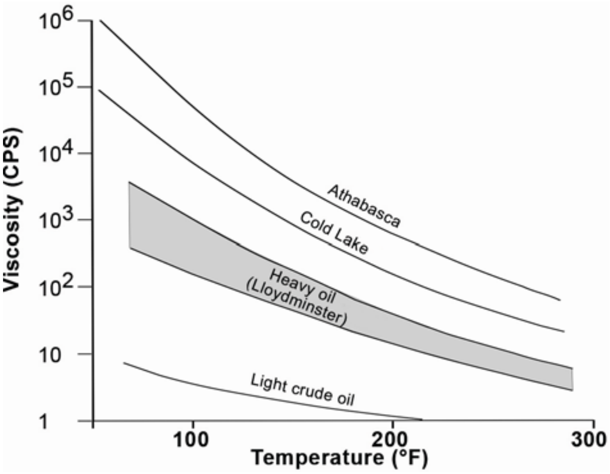
Caspian, Timan-Pechora, and Volga-Ural basins are geologically similar to the Western Canada Sedimentary Basin. Very large resources occur in the basins of the Siberian Platform of Russia (Meyer and Freeman, 2006). Many more deposits are identified worldwide but, as in the case of oil seepages, no resource estimates are reported for them. The volumes of discovered and prospective additional bitumen in place amount to 2 469 billion barrels and 803 billion barrels, respectively.

Extra-heavy oil

Extra-heavy oil is recorded in 166 deposits world wide (Table 4-2). Extra-heavy oil deposits are found in 22 countries, with 13 of the deposits being located offshore or partially offshore (Table 4-2). Only one deposit is sufficiently large to have a major supply and economic impact on crude oil markets. That deposit, the Orinoco Oil Belt (Fig. 4-2) in the Eastern Venezuela Basin, accounts for about 90% of the discovered plus prospective extra-heavy oil in place, or about 2.2 trillion barrels. In 2005 the upgraded extra-heavy oil produced from this deposit amounted to about 570 thousand b/d, and accounted for almost 20% of the oil production of Venezuela, the world's third leading crude oil exporter. Some of the deposits are separate reservoirs or a single field that consist entirely of extra-heavy oil, whereas other deposits occur as extra-heavy oil reservoirs associated with conventional oil reservoirs in fields known to be primarily conventional. The extra-heavy oil of the Orinoco Oil Belt does not occur with conventional oil reservoirs. Table 4-2 shows in place discovered volume and total in place volumes amounting to 2 294 billion barrels and 2 484 billion barrels, respectively.

In total, Tables 4-1 and 4-2 report a total in-place bitumen volume of 5 756 billion barrels. This volume is slightly *less than, but of the same order of magnitude as, the estimated volume of original oil in place in the world's known conventional oil fields.* Successful commercial production from the Orinoco Oil Belt and the Alberta bitumen accumulations have proven production strategies and technologies that are likely to be applied to the smaller accumulations represented in Tables 4-1 and 4-2. With the recognition of the commercial potential of these immense resources, *additional* deposits and volumes are likely to be reported in the future.

Figure 4-3 Response of viscosity to change in temperature for some Alberta oils
Source: Raicar and Procter, 1984



Economics of Production, Transportation, and Refining Technology

Production technologies: Canada

Natural bitumen deposits occurring at depths of up to 250 feet can be surface-mined. The bitumen is then separated from the mined sand by a hot water process. The bitumen mined at two of the three operating mining/separation projects (Suncor Energy and Syncrude Canada) is upgraded onsite into a synthetic crude oil (SCO), which is then transported by pipeline to conventional refineries. The third project, Albian Sands Energy, transports a mixture of bitumen and diluents to the Scotford upgrading facility about 270 miles south, near Edmonton. In 2005, mined production amounted to 551 thousand b/d for the three Alberta oil sand mining projects. Of the 174 billion barrels of bitumen estimated by the Alberta Energy and Utilities Board (EUB, 2006) to be recoverable from identified deposits, 32 billion barrels is accessible with current surface-mining technology.

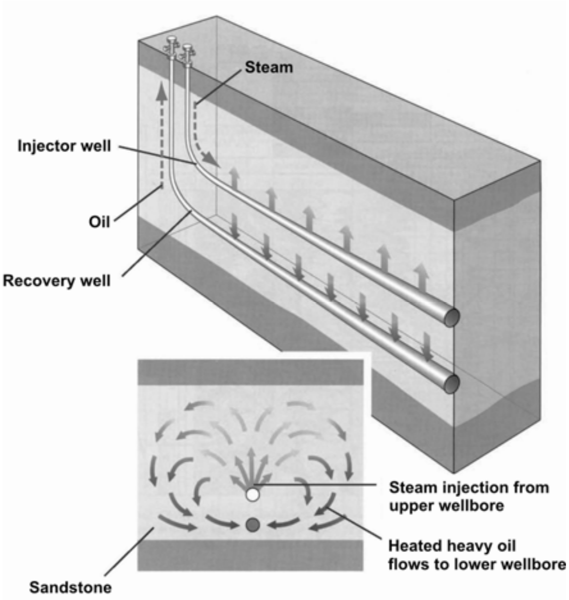
In a limited number of areas, bitumen that is too deep for surface mining is produced from wells for short periods without injection of steam. In cold production with sand (Cold heavy oil production with sand - CHOPS) bitumen and sand are pumped to the surface through the well bore and then separated. Sand production creates channels or high-permeability zones for the bitumen to flow through (Dusseault, 2001).

Most bitumen deposits are not amenable to cold production over extended periods, so steam is commonly injected into the reservoir to raise the temperature and reduce the viscosity of the bitumen. Fig. 4-3 shows the dramatic reduction in fluid viscosity with increasing temperatures for the bitumen at Athabasca and Cold Lake. Steam can be injected through vertical or lateral (horizontal) wells. At Cold Lake, bitumen has historically been produced with cyclic steam stimulation. In this process, steam is injected into the formation during the 'soak' time period or cycle to heat the formation. The production cycle begins after injection wells are converted to producers and ends when the heat is dissipated within the produced fluids. This cycle of soak and produce is repeated until the response becomes marginal because of increasing water production and declining reservoir pressure. After a number of cycles, steam may also be injected as a steam flood to improve reservoir pressure (Dusseault, 2006).

An alternative extraction method is the steam-assisted gravity drainage (SAGD) process (Fig. 4-4), where a horizontal steam-injection well is drilled about 5 metres above a horizontal

Figure 4-4 Stacked pair of horizontal wells, SAGD natural bitumen recovery

Source: Graphic copyright Schlumberger *Oilfield Review*, used with permission, [Curtis, et al., 2002]



production well. Injected steam creates a heated chamber, the heated bitumen is mobilised, and gravity causes the fluid to move to the producing well where it is pumped to the surface. Diluents may also be injected to assist in lowering the viscosity of the reservoir fluids.

When the EUB estimates recoverable bitumen resources it assumes the following recovery factors for the original bitumen in place: cold production, 5%; cyclic thermal production at Cold Lake, 25%; SAGD at Peace River, 40%; and SAGD at Athabasca, 50%. The EUB estimate of the recovery efficiency of mining and extraction of the in-place bitumen is 82% (National Energy Board [NEB], 2006).

Production technology: Venezuela

In the Orinoco Oil Belt, cold production of extra-heavy oil is achieved through multilateral (horizontal) wells that are precisely positioned in thin but relatively continuous sands, in combination with electric submersible pumps and progressing cavity pumps. Horizontal multilateral wells maximise the borehole contact with the reservoir. Extra-heavy oil mobility in the Orinoco Oil Belt reservoirs is typically greater than that of bitumen in the Alberta sands because of higher reservoir temperatures, greater reservoir permeability, higher ratio of gas to oil, and the lower viscosity of extra-heavy oil (Dusseault, 2001). Efforts are also continuing to improve production of viscous oil through down-hole electrical resistance heating.

The recovery factor for the cold production of extra-heavy oil in the Orinoco is estimated to be 8-12% of the in-place oil. It is fully expected that the Orinoco projects will install enhanced recovery methods after the cold production phase of recovery is completed. While it is generally recognised that thermal recovery methods will be applied following cold production, other tertiary recovery methods involving gas injection and in-situ combustion could also be profitably applied to the extra-heavy oil and natural bitumen reservoirs following steam thermal recovery methods (Dusseault, 2006).

Production economics: Canada

Fig. 4-5 shows the NEB estimates of bitumen and synthetic oil supply costs in 2005 Canadian dollars (1 CDN$ = US$ 0.85). The NEB cost estimates assume a US price of West Texas Intermediate of US$ 50/bbl, NY Exchange price of gas at US$ 7.5/million Btu and a 10% real return. Costs associated with cold production

Figure 4-5 Estimates of operating (Opex) and supply costs by production method
Source: NEB, 2006

Production method	Product	Opex	Supply cost
	[CDN$ (2005) * per barrel at plant gate]		
Cold (Wabasca, Seal)	Bitumen	6-9	14-18
Cold heavy oil with sand (Cold Lake)	Bitumen	8-10	16-19
Cyclic steam (Cold Lake)	Bitumen	10-14	20-24
SAGD	Bitumen	10-14	18-22
Mining/extraction	Bitumen	9-12	18-20
Integrated/mining extraction, upgrading	Syncrude **	18-22	36-40

* Canadian dollar assumed at US$ 0.85
** SCO

are low because of low operating costs. However, recovery by cold production is also low and for the Alberta sands not sustainable for long periods of time. The SAGD process costs appear to be slightly lower than cyclic steam costs. The range of costs for the mining/extraction process is within the cost range of the SAGD process. The NEB's published per barrel cost of supply estimates were based on historical information, regulatory filings for new operations, and internal engineering cost models. The capital investment costs are CDN$ 15 000 - 20 000 per sustainable daily barrel (NEB, 2006), so a project capable of producing 30 000 b/d would have a nominal investment cost of CDN$ 450 to 600 million.

In most cases operating costs account for half of the supply costs. For the thermal processes, the cost of natural gas used to generate steam makes up approximately 65-75% of operating costs. Under favourable conditions, each barrel of bitumen produced consumes 1.05 thousand cubic feet of natural gas, based on a steam-to-oil ratio of 2.5:1. If gas is used as fuel in the mining/extraction configurations, gas requirements are 0.7 thousand cubic feet per barrel of bitumen produced. There is great concern regarding the large volumes of water and natural gas used in the thermal recovery processes. Recent research has focused on reducing thermal process gas requirements by substituting other fuels or by reducing the steam-to-oil ratio by injecting solvents into the reservoir. Unless there is onsite upgrading to SCO, the product that will be transported to upgrading facilities will be a blend of two-thirds bitumen and one-third diluents. The availability of natural gas liquids or light oil to use as diluents in transporting the bitumen to upgrade facilities is also a potential challenge to expansion.

Production economics: Venezuela

The unit supply cost for the Orinoco extra-heavy oil utilising cold production is much lower than the supply cost for cold production of bitumen in Canada because of more favourable fluid and reservoir conditions. The sustainability of a well production plateau is much longer, and the level well production is as much as an order of magnitude higher in Orinoco extra-heavy oil than in the Canadian bitumen projects. Current estimates of the supply costs for the Orinoco extra-heavy crude oil are as little as half of the supply cost for Canadian bitumen (Fig. 4-4).

Transportation and Upgrading

Transportation technology

The transportation of the extra-heavy oil and bitumen outside the concession or lease requires that the oil be heated, or alternatively blended with diluents (naphtha, gas condensates, or light oils), to reduce viscosity, or the oil be upgraded on-site. The degree of upgrading depends on the quality of the extracted oil and the desired standard of the SCO, that is, the target API gravity and sulphur content. In many cases the specifications for the SCO will depend on the availability of merchant refinery capacity capable of accepting and profitably refining it, or specifications may depend on the requirements of a captive refinery. A captive refinery is one that is obligated because of ownership or contract to refine a particular producer's crude oil.

Upgrading technology

For light oil refinery feedstock, simple atmospheric/vacuum distillation processes might yield an acceptable slate of primary products that included high-value transportation fuels: gasoline, jet fuel, and diesel fuels. With simple distillation, the heavier the refinery feedstock oil, the lower the yield of high-value transportation fuels and the higher the percentage residuum yield. Refineries steeply discount the price they are willing to pay for the heavy oil feedstocks that have low yields of the high-value products.

The upgrading process of heavy oil and natural bitumen starts with atmospheric and vacuum distillation processes that recover the diluents for recycling to the field, and which also produce gas oil and residue. The gas oil can be treated with hydrogen to reduce sulphur and nitrogen (producing hydrogen sulphide and ammonia). The two options are hydrotreating (a catalytic reaction) and hydrocracking the gas oil (carried out under mild conditions). The typical options for treating the residue (often called resid conversion) are (1) solvent deasphalting applied as pretreatment of the residue for removal of asphaltic materials (Speight, 1991), (2) visbreaking, which is a mild thermal cracking operation used to reduce the viscosity of the residue, producing a low-grade gasoline, heavy gas oil distillates, and a residual tar, (3) coking, which is used to break the heaviest fractions of the residue into elemental carbon (coke) and lighter fractions, and (4) hydrocracking, which adds hydrogen as the residue is heated under high temperature and high pressures (high conversion), so that liquid yields are maximised under high conversion (Vartivarian and Andrawis, 2006). Hydrogen for hydrotreating and hydrocracking is either purchased or generated by passing natural gas over steam (steam-methane reforming process). Because the residue hydrocracking occurs under extremely high temperatures and pressures, investment costs for process equipment are much higher than for the other resid conversion processes (Speight, 1991).

Bitumen upgrading: Canada

The yield of upgraded oil (SCO) from natural bitumen, based on data from Alberta, varies with the technology employed, the consumption of the product for fuel in the upgrader, the extent of natural gas liquids recovery, and the degree of residue upgrading. The Suncor, Syncrude, and Albian Sands projects mine natural bitumen and extract the oil from the mined sand. The Suncor project uses delayed coking for a yield of 0.81 barrels of oil per barrel of natural bitumen input. The Syncrude project, which uses fluid coking combined with hydrocracking the gas oil fraction, has a yield of 0.85 barrels of oil per barrel of bitumen (Speight, 1990). The yield for the Albian Sands upgrading plant at Scotford, which applies hydrocracking to both the distillation gas oil and residue, is 0.9 (NEB, 2004).

Figure 4-6 Commercial operations in the Orinoco Oil Belt
Source: US DOE Energy Information Administration, 2006

Project name (new name)	**Petrozuata (Junin)**	**Cerro Negro (Carabobo)**	**Sincor (Boyaca)**	**Hamaca (Ayacucho)**
Startup	October 1998	November 1999	December 2000	October 2001
Extra-Heavy Oil Production - b/d	120 000	120 000	200 000	200 000
API gravity	9.3°	8.5°	8.0-8.5°	8.7°
Synthetic Oil production - b/d	104 000	105 000	180 000	190 000
API gravity	19-25°	16°	32°	26°
Sulphur - % weight	2.5	3.3	0.2	1.2

As of 2005, about 60% of the crude bitumen produced in Alberta was converted into various grades of SCO. The remaining 40% was blended with diluents (light oils, gas condensates or natural gas liquids) and shipped to refiners having the capability to accept the heavy oil blend. The diluents account for 33% of the blend (NEB, 2006). New and expansion projects could increase bitumen production to 3 mb/d by 2015 (Alberta EUB, 2006). If such an expansion is realised, on-site upgrading could be attractive to both mining and in-situ projects, by eliminating the need for diluents for transportation. Their elimination would reduce the volume of diluents the industry needs and increase the effective capacity of product pipelines to refineries. The by-product coke from upgrading plants could provide a substitute for the natural gas used for steam generation for in-situ projects (Luhning, et al., 2002). The principal challenges are the additional capital cost required and the scale of the bitumen production project needed to take advantage of economies of scale at the upgrading facility.

Extra-heavy oil upgrading: Orinoco Oil Belt

Fig. 4-6 shows the upgrade plant capacities and product specifications for the four commercially-operating Orinoco extra-heavy oil production projects. Upgrading occurs before export because of the limited availability of light Venezuelan crude oils for blending and the location of the upgrading plants on the northeast coast of Venezuela. All of the plants recover and recycle diluents to their fields. Each also uses delayed coking to upgrade residue and hydrotreat the coking process by-product naphtha for removal of sulphur and nitrogen. The Sincor project produces a low-sulphur light SCO by hydrocracking the heavy gas oil generated from gasifying part of the coke from the coking process. The conversion efficiency of extra-heavy oil into synthetic crude varies from 87-95%. Although the light and low-sulphur synthetic oils are generally the easiest to market to refiners and command the highest prices, most of the lower-quality synthetic crude oil produced by the Petrozuata and Cerro Negro projects are transported to captive refineries in the US and Caribbean (Chang, 1998). The extracted extra-heavy oil and bitumen-diluent blends require similar upgrading processes, suggesting that upgrading costs will be comparable.

Economics of Upgrading and Markets for Upgraded Oil

Fig. 4-7 shows selected published estimates of capital costs (Vartivarian and Andrawis, 2006) that were expressed on a per daily barrel of (upgraded) synthetic oil (syncrude) plant output capacity. The purpose of the Vartivarian and Andrawis study was to compare costs of a number of alternative plant process configurations having a nominal input capacity of 100 000 b/d of bitumen/diluent feedstock, consisting of 80% bitumen and 20% diluent. The bitumen had an assumed gravity of 8.6° API and a sulphur content of 4.8%. Fig. 4-7 shows plant process investment cost and investment per barrel of output capacity, along with the syncrude product specifications. The investment

Figure 4-7 Investment cost per daily barrel for upgrading bitumen to various grades of synthetic crude oil
Source: Vartivarian and Andrawis, 2006

Process configuration	Syncrude output (b/d)	API Gravity (API°)	Sulphur (wt %)	Investment cost ($ million)	Capex * ($ thousand per daily barrel)
RVBR	81 508	12.5	4.10	889	10.9
GOHT	80 048	18.0	3.80	1 278	16.0
GOHT, RVBR	84 576	20.8	3.30	1 333	15.8
SDA, GOHC	86 900	23.6	3.20	1 350	15.5
RDCK, GOHT	67 538	32.4	0.13	1 250	18.5
RDCK, GOHC	71 009	46.8	0.00	1 556	21.9
RHCR, GOHT	87 832	25.9	0.90	1 694	19.3
RHCR, GOHC	93 126	40.4	0.90	2 000	21.5

* Capex = capital investment per daily barrel of plant output capacity
RVBR = visbreaking applied to residue from distillation processes
GOHT = hydrotreating of gas oil from distillation processes
SDA = solvent de-asphalting applied to residue from distillation processes
GOHC = hydrocracking of gas oil from distillation processes
RDCK = delayed coking applied to residue from distillation processes
RHCR = hydrocracking applied to residue from distillation processes
Assumed 100 000 b/d input of which 20 000 b/d is diluent recycled to field, 80 000 b/d bitumen at 8.6° API gravity and 4.8% sulphur
All configurations assume bitumen is passed through atmospheric/vacuum distillation processes
Costs are 2005 US$

costs were based on US Gulf Coast costs in 2005 US dollars. The greater the intensity of the processing, as indicated by the quality of the synthetic oil product (higher API gravity and lower sulphur content), the higher the investment cost per daily barrel. The plant investment costs are from 29-36% greater when the high temperature/pressure residue hydrocracking process (configurations with RHCR – Fig. 4-7) is used than if the residue is coked (configurations with RDCK – Fig. 4-7). The configurations with this higher cost process (RHCR), however, result in 30% greater synthetic oil output than under coking. The economic benefits of the higher-cost process depend on syncrude prices.

The two features to notice about Fig. 4-7 are firstly, the wide range in initial investment costs per daily barrel of synthetic crude oil output and secondly, the absolute level of investment required; never less than 800 million dollars and could easily exceed 2 billion dollars. The investment per daily barrel of bitumen production capacity (mine and extraction or in-situ recovery) is of the same order of magnitude as the required investment per daily barrel for the upgrader facility. If the per daily barrel of production cost was CDN$ 20 000 or US$ 17 000, the combined cost of the production/upgrading facility for a high-quality syncrude could be US$ 37 000 per daily barrel, or almost US$ 3 billion for an integrated project to supply the upgrader at 80 000 barrels of bitumen per day. Such capital requirements would be well beyond the reach of small operators.

Plants that upgrade extra-heavy oil and bitumen demonstrate the generic characteristics of chemical process industries. They are subject to significant economies of scale, that is, unit capacity investment cost increases rapidly as capacity is reduced below optimal size, and optimal-size plants must operate at high utilisation rates to be profitable. The most profitable upgrade plant design depends on the value placed on its synthetic crude product by refinery purchasers, as well as on the cost of inputs to the upgrade plant. This market value is determined by the availability of competing crude oils of the same or superior quality and

Occurrences of natural bitumen and extra-heavy oil are widespread; the volume of oil in place appears to be of at least the same order of magnitude as the volume of original oil in place at known conventional oil accumulations.

the technical capability of local or captive refineries to accept the crude and in turn, to produce high-value products.

Past conduct may indicate the pattern of future development. Partners of the Petrozuata and Cerro Negro projects in the Orinoco Oil Belt had captive US and Caribbean refineries which influenced the design of the San Jose upgrading facilities. The initial Canadian mining operations built on-site upgrading facilities that produced a syncrude that was matched with available refinery capacity.

Downstream vertical integration is the economic term used when a raw materials producer performs the next stages of processing, such as refining or smelting and even selling finished products. Alternatively, if a steel maker starts a mining subsidiary to supply the ore to the steel plant, it is upstream vertical integration. A primary motivation for economic integration downstream is to manage the risks inherent in raw materials markets by providing a means through a captive upgrading facility and perhaps refinery to market the bitumen product. The refiner's price differential between heavy oil and light oil can be notoriously unstable, so there is a real risk to the bitumen producer of its being unable to recover costs, particularly in the light of the relatively high raw bitumen production supply costs presented in Fig. 4-5. In general, in a rising price regime heavy oil price increases will be smaller on a dollar basis than light oil prices, leading to an increasing price differential. The price differential between light and heavy oil also increases as inventories build at refineries. A prolonged period of oversupply of conventional oil and the subsequent bitumen price decline could drive prices to levels below operating cost. It is not surprising that most of the announced new projects specify either a captive upgrading facility or a strategic alliance (de-facto vertical integration) between producers, merchant upgrading plants, and refiners as a response to market risks.

Summary and Implications

Occurrences of natural bitumen and extra-heavy oil are widespread; the volume of oil in place appears to be of at least the same order of magnitude as the volume of original oil in place at known conventional oil accumulations. The Alberta bitumen deposits are the only bitumen projects that are currently produced and upgraded to refinery feedstock or SCO. The commercially successful Orinoco Oil Belt and Alberta oil sands extraction and upgrading technologies will probably be applied to other deposits listed in Tables 4-1 and 4-2. These projects have demonstrated, at least for the Orinoco Oil Belt and the Canadian oil sands, that these resources can be extracted and upgraded at rates that make an important contribution to each country's petroleum supply and at costs that are currently competitive with conventional non-Opec resources.

Estimates of supply costs per barrel for natural bitumen are higher than for many sources of conventional crude oil supply. Moreover, market prices of raw bitumen/diluent blend are discounted by refiners relative to conventional oil prices. As a response to the risk in the volatility of bitumen and heavy oil prices, operators of new projects will either vertically integrate extraction with upgrader/refinery facilities or develop alliances for upgrading/refining their extracted product.

Venezuela has agreements with several national oil companies to evaluate areas of the Orinoco Oil Belt outside of the current project areas for expansion of its extra-heavy oil production base. In Canada the large number of proposed projects that would expand bitumen production has raised some concern about the adequacy of natural gas, diluents, and fresh water supplies. The technologies known as VAPEX (Vapor-Assisted Petroleum Extraction) and THAI (Toe-to-Heel Air Injection) are designed to address the water and gas inadequacy concerns. These are in the field testing stages. In the VAPEX process, a mixture of light hydrocarbon liquids is injected into the reservoir to enhance the reduction in bitumen viscosity induced by steam injection. The enhancement of viscosity reduction brought about by the VAPEX process reduces the steam (water and natural gas) requirements for SAGD projects. The THAI process entails igniting oxygen through a vertical air injection well to lower the viscosity of the bitumen and then recovering the bitumen through a horizontal production well, thus eliminating the need for gas and water for steam injection.

Emil Attanasi
Richard F. Meyer
US Geological Survey

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DEFINITIONS

In this chapter the following definitions apply:

Discovered original oil in place: the volume of oil (natural bitumen/extra-heavy oil) in place reported for deposits or parts of deposits that have been measured by field observation. In the literature, estimates of the in-place volumes are often derived from the physical measures of the deposit; areal extent, rock grade, and formation thickness.

Prospective additional original oil in place: the oil in unmeasured parts of a deposit believed to be present as a result of inference from geological (and often geophysical) study.

Original oil in place: the amount of oil in a deposit before any exploitation has taken place. Where original oil in place is not reported, it is most often calculated from reported data on original reserves (cumulative production plus reserves). Although admittedly inexact, this is a reasonable way to describe the relative abundance of the natural bitumen or extra-heavy oil.

Original reserves: reserves plus cumulative production. This category includes oil that is frequently reported as estimated ultimate recovery, particularly in the case of new discoveries.

Cumulative production: total of production to latest date.

Reserves: those amounts of oil commonly reported as reserves or probable reserves, generally with no further distinction, are quantities that are anticipated to be technically (but not necessarily commercially) recoverable from known accumulations. Only in Canada are reserves reported separately as recoverable by primary or enhanced methods. Russian A, B, and C1 reserves are included here. The term reserve, as used here, has no economic connotation.

Coking: a thermal cracking process that converts the heavy fraction of residue or heavy oils to elemental carbon (coke) and to lighter fractions of the residue, including naphtha or heavy gas oils.

Conventional oil: oil with an API gravity of greater than 20° (density below 0.934 g/cm^3). API gravity is the inverse of density and is computed as (141.5/sp g)-131.5 where sp g is the specific gravity of oil at 60 degrees Fahrenheit.

Cracking: a general term used for a process in which relatively heavy hydrocarbons are broken down into smaller, lower-boiling molecules.

Delayed coking: a coking process that recovers coke and produces heavy gas oils from the residuum following the initial distillation of the feedstock oil. The process uses at least two sets of large drums that are alternatively filled and emptied while the rest of the plant operates continuously. Drum temperatures are 415° to 450°C.

Extra-heavy oil: extra-heavy oil is commonly defined as oil having a gravity of less than 10° and a reservoir viscosity of no more than 10 000 centipoises. In this chapter, when reservoir viscosity measurements are not available, extra-heavy oil is considered to have a lower limit of 4° API.

Flexi-coking: an extension of fluid coking, which includes the gasification of the coke produced in the fluid coking operation and produces a coke gas (Speight, 1986). Flexi-coking is an ExxonMobil proprietary process.

Fluid Coking: a continuous coking process where residuum is sprayed onto a fluidised bed of hot coke particles. The residuum is cracked at high temperatures into lighter products and coke. Coke is a product and a heat carrier. The process occurs at much higher temperatures than delayed coking but leads to lower coke yields and greater higher liquid recovery. Temperatures in the coking vessels are from 480° to 565°C (Speight, 1986). Fluid coking is an ExxonMobil proprietary process.

Gas oil: hydrocarbon mixture of gas and oils that form as product of initial distillation of bitumen or heavy oil feedstock.

Heavy oil: Oil with API gravity from 10° to 20° inclusive (density above 1.000 g/cm^3).

Hydrocracking: a catalytic cracking process that occurs in the presence of hydrogen where the extra hydrogen saturates or hydrogenates the cracked hydrocarbons.

Natural bitumen: natural bitumen is defined as oil having a viscosity greater than 10 000 centipoises under reservoir conditions and an API gravity of less than 10°API. In this chapter, when reservoir viscosity measurements are not available, natural bitumen is taken as having a gravity of less than 4°. (Natural bitumen is immobile in the reservoir. Because of lateral variations in chemistry as well as in depth, and therefore temperature, many reservoirs contain both extra-heavy oil, and occasionally heavy oil, in addition to natural bitumen).

Oil Field: a geographic area below which are one or more discrete reservoirs from which petroleum is produced. Each reservoir may be comprised of one or more zones, the production from which is commingled. The production from the reservoirs may be commingled, in which case production and related data cannot be distinguished.

TABLES

Table Notes

The data in the tables are estimates by Richard Meyer of the US Geological Survey. They have been based upon a detailed review of the literature combined with available databases, and suggest (but do not define) the resource volumes that could someday be of commercial interest.

Table 4-1 Natural Bitumen: resources, reserves and production at end-2005

	Deposits	Discovered original oil in place	Prospective additional original oil in place	Total original oil in place	Original reserves	Cumulative production	Reserves
	(number)			(million barrels)			
Angola	3	4 648		4 648	465		465
Congo (Brazzaville)	1	63		63	6		6
Congo (Democratic Rep.)	1	300		300	30		30
Madagascar	1	2 211		2 211	221		221
Nigeria	1	5 744	32 580	38 324	574		574
Total Africa	**7**	**12 966**	**32 580**	**45 546**	**1 296**		**1 296**
Canada	227	1 693 843	703 221	2 397 064	178 580	4 975	173 605
Trinidad & Tobago	14	628		628			
United States of America	201	37 142	16 338	53 479	24	24	
Total North America	**442**	**1 731 613**	**719 559**	**2 451 171**	**178 604**	**4 999**	**173 605**
Venezuela	1						
Total South America	**1**						
Azerbaijan	3	<1		<1	<1		<1
China	4	1 593		1 593	1		1
Georgia	1	31		31	3		3
Indonesia	1	4 456		4 456	446	24	422
Kazakhstan	52	420 690		420 690	42 009		42 009
Kyrgyzstan	7						
Tajikistan	4						
Uzbekistan	8						
Total Asia	**80**	**426 771**		**426 771**	**42 460**	**24**	**42 436**
Italy	14	2 100		2 100	210		210
Russian Federation	39	295 409	51 345	346 754	28 380	14	28 367
Switzerland	1	10		10			
Total Europe	**54**	**297 519**	**51 345**	**348 864**	**28 590**	**14**	**28 577**

Table 4-1 Natural Bitumen: resources, reserves and production at end-2005

	Deposits	Discovered original oil in place	Prospective additional original oil in place	Total original oil in place	Original reserves	Cumulative production	Reserves
	(number)			(million barrels)			
Syria (Arab Rep.)	1						
Total Middle East	**1**						
Tonga	1						
Total Oceania	**1**						
TOTAL WORLD	**586**	**2 468 869**	**803 484**	**3 272 352**	**250 950**	**5 037**	**245 914**

Source: R.F. Meyer, U.S. Geological Survey

Table 4-2 Extra-Heavy Oil: resources, reserves and production at end-2005

	Deposits	of which: deposits offshore	Discovered original oil in place	Prospective additional original oil in place	Total original oil in place	Original reserves	Cumulative oil production	Reserves
	(number)	(number)			(million barrels)			
Egypt (Arab Rep.)	1		500		500	50		50
Total Africa	**1**		**500**		**500**	**50**		**50**
Canada	4							
Mexico	2		60		60	6	5	1
Trinidad & Tobago	2		300		300			
United States of America	54	1	2 609	26	2 635	235	216	19
Total North America	**62**	**1**	**2 969**	**26**	**2 995**	**241**	**221**	**20**

Table 4-2 Extra-Heavy Oil: resources, reserves and production at end-2005

	Deposits	of which: deposits offshore	Discovered original oil in place	Prospective additional original oil in place	Total original oil in place	Original reserves	Cumulative oil production	Reserves
	(number)	(number)			(million barrels)			
Colombia	2		380		380	38	8	30
Cuba	1	1	477		477	48		48
Ecuador	3		919		919	92	50	42
Peru	2		250		250	25	18	7
Venezuela	33	2	2 256 159	189 520	2 445 679	72 556	14 001	58 555
Total South America	**41**	**3**	**2 258 185**	**189 520**	**2 447 705**	**72 759**	**14 077**	**58 682**
Azerbaijan	1		8 841		8 841	884	759	125
China	12		8 877		8 877	888	137	750
Uzbekistan	1							
Total Asia	**14**		**17 718**		**17 718**	**1 772**	**896**	**875**
Albania	2		373		373	37	3	34
Germany	1							
Italy	31	6	2 693		2 693	269	179	90
Poland	2		12		12			
Russian Federation	6		177		177	6		6
United Kingdom	2	2	11 850		11 850	1 085	1 009	76
Total Europe	**44**	**8**	**15 105**		**15 105**	**1 397**	**1 191**	**206**
Iran (Islamic Rep.)	1	1						
Iraq	1							
Israel	2		2		2	<1		<1
Total Middle East	**4**	**1**	**2**		**2**	**1**		**1**
TOTAL WORLD	**166**	**13**	**2 294 479**	**189 546**	**2 484 025**	**76 220**	**16 385**	**59 834**

Source: R.F. Meyer, U.S. Geological Survey

COUNTRY NOTES

With the exception of Canada, the Country Notes on Natural Bitumen and Extra-Heavy Oil have been compiled by the authors of the Commentary. Names of sedimentary basins and reference locations are from *Sedimentary Provinces of the World* by St. John, Bally and Klemme (1984). In the case of Canada, the information has been supplied by the WEC Member Committee.

Albania

Two of Albania's oil fields contain extra-heavy oil accumulations, both located in the Durres Basin.

Angola

Two natural bitumen deposits are located in the Cuanza Basin in Bengo province. They contain about 4.5 billion barrels of oil in place, but have not been worked as an energy source. Their development could be an option after most of Angola's conventional oil resources have been produced.

Azerbaijan

The natural bitumen resources are small and will probably not be used as a source of energy in the near future. The deposits are located within the South Caspian Basin, and the best known is Cheildag (Waters, 1974). The large extra-heavy oil accumulation was discovered in 1904.

Canada

Canada has three major oil sands deposits in Alberta, the Athabasca deposit, centered on the city of Fort McMurray, the Cold Lake deposit, north of Lloydminster, and the Peace River deposit, in northwest Alberta.

In the Athabasca area, where 80% of oil sands exist, the mineable portion of the Wabiskaw-McMurray formation (Cretaceous age) is estimated to contain 16 billion cubic metres in-place. A further 253 bcm of in-place bitumen resource is associated with the in-situ projects.

The Canadian Association of Petroleum Producers (CAPP) estimates of established reserves at year-end 2004 were 28 bcm, which is consistent with Alberta Energy and Utilities Board (EUB). Cumulative production is about 0.7 bcm. About 20% of established reserves are mineable and 80% require in-situ recovery. The ultimate potential (with improved economics and technology) of bitumen reserves is 55 bcm, including 8 bcm from surface mineable recovery methods.

Mineable Reserves. The surface-mineable oil sands area is defined by the amount of overburden that has to be removed to reach bitumen ore. Overburden of 75 m or less is considered to be surface-mineable. The EUB has designated over 850 000 acres where the overburden is less than 75 m. All other oil sands deposits that are below 75 m of depth are classified as in-situ. Due to low gravity and high viscosity, these oil sands require enhanced recovery schemes, such as thermal stimulation, in order for the bitumen to become mobile and produceable by pumping.

The quantity of volume in-place that is economic to produce is based on economic strip ratio

Oil Sands Mining Projects

Operator	Project	Capacity 000 m^3/d		Expansion
		Current	Projected	
Syncrude	Syncrude	56	80	2012-15
Suncor	Millennium/Voyageur	41	80	2008-12
Shell	Athabasca	25	96	2010-15
CNRL	Horizon		37	2009-11
True North/UTS	Fort Hills		32	2011-14
Imperial	Kearl Lake		48	2011-15
Synenco	Northern Lights		16	2011-13
Total	Joslyn		32	2011-14
Fort MacKay First Nation			8	

criteria, a minimum bitumen saturation of 7 mass per cent bitumen, and a minimum saturated zone thickness of 3.0 m. The EUB also applies factors that sterilise volumes from being mineable, such as corridors along rivers, surface facilities, tailings ponds, and waste dumps. Mining and extraction operations result in an average loss of 18% of bitumen in-place volume.

Active projects shown in the table above have produced 0.5 bcm at end-2004. The Suncor mining project began operation in 1967, produced less than 8 000 m^3/d for most of the period through the end of the 1980s, and then grew to production of 35 000 m^3/d in 2004. The Syncrude project began operation in 1977 and has produced over 32 000 m^3/d since 1995. The Albian project, led by Shell Canada, began operation in January 2004 and reached its design capacity of 25 000 m^3/d in mid-2005.

In-Situ Reserves. Established reserves are based on economic cutoff limits and recovery factors. Commercial projects, given production history, were assigned thermal recovery factors from 25-40%, depending on the producing formation. A relatively small quantity, 0.2 bcm, has been produced by in-situ projects.

Prior to the extraordinary increase in world crude oil prices since 2002, thermal production of bitumen from oil sands was stagnant, at approximately 48 000 m^3/d. Supply was dominated by cyclic steam projects of Imperial Oil at Cold Lake, and Canadian Natural Resources at Primrose, both projects initiated before the 1986 collapse in world oil prices. The 1996 agreement between Alberta and Ottawa on a generic oil sands regime, and the recovery of world prices which began in early 1999 encouraged the owners of oil sands to begin cautiously advancing in-situ projects. Since 2002, project proposals have grown dramatically.

The following table summarises the largest commercial and proposed projects.

Oil sands production will become an increasing part of Canada's crude oil supply, despite some challenges such as: capital cost escalation, operating costs, labour and infrastructure availability.

Record high oil prices have raised international awareness of Alberta's oil sands resources. Proposed projects for surface mining and in-situ reserves have mushroomed in the heated market for crude supply. Recent projections suggest that oil sands output could increase to between 240 000 m^3/d and 480 000 m^3/d by 2015, depending on the economic conditions.

China

Four natural bitumen accumulations have been identified in the Junggar Basin with resources of about 1.6 billion barrels of bitumen. Ten of the 12 extra-heavy oil accumulations are located in the Bohai Gulf Basin with the other two located in the Huabei and the Tarim Basins.

Columbia

The two extra-heavy oil accumulations are part of a single field in Colombia in the Barinas-

Oil Sands In-Situ Projects

Operator	Project	Capacity 000 m^3/d		Expansion
		Current	Projected	
Imperial	Cold Lake	24	29	
EnCana	Foster Creek	6	80	2006-15
Suncor	Firebag	5	19	2006-12
Petro-Canada	MacKay River	5	11	
Blackrock		2	4	2012
Shell	Cadotte Lake	2	16	2010-15
CNRL	Birch Mountain		43	2012-18
Husky	Sunrise		32	2008-15
Nexen/Opti	Long Lake		23	2007-10
Conoco-Phillips/Total	Surmont		16	2006-12
Others		19	45	2006-10

Apure Basin. There are numerous oil seepages and small bitumen deposits, especially in the Middle and Upper Magdalena Basins. None of these deposits appears to be sufficiently large to be an important commercial source of synthetic oil.

Congo (Brazzaville)

Heavy oil is found in reservoirs offshore Congo but no extra-heavy oil is known. The natural bitumen deposit at Lake Kitina in the Cabinda Basin has been exploited for road material.

Congo (Democratic Republic)

A natural bitumen deposit occurs in the Democratic Republic of Congo in the Cabinda Basin near the border with Cabinda. It has served as a source of road material, with nearly 4 000 tonnes (24 000 barrels) having been produced in 1958. This deposit is not likely to become a source of synthetic oil.

Cuba

Most of the oil produced from Cuba is heavy. Cuba contains numerous oil seepages but no significant natural bitumen accumulations. The extra-heavy oil accumulation is located partially offshore in the Florida-Bahamas Basin (also called the Greater Antilles Deformed Belt).

Ecuador

Ecuador is endowed with large amounts of heavy oil but only a small amount, all in the Putamayo Basin, is extra-heavy. Natural bitumen is restricted to scattered oil seepages.

Egypt (Arab Republic)

Many fields containing heavy oil are found in Egypt, but very little of this is extra-heavy. The single extra-heavy oil accumulation is undeveloped.

Georgia

The only significant natural bitumen deposit in Georgia is in the South Caspian Basin, at Natanebi. Neither heavy nor extra-heavy oil are known in Georgia, although conventional oil has been produced there for more than a century.

Germany

Heavy oil is produced from many fields in Germany, but extra-heavy oil has not been reported. Highly viscous natural bitumen is present in the Nordhorn deposit, in the Northwest German Basin.

Indonesia

In Indonesia, although many fields produce heavy oil, there does not appear to be a large extra-heavy oil resource. Natural bitumen occurs in the well-known Buton Island deposit. This has long been utilised as a source of road asphalt.

Iran (Islamic Republic)

The principal extra-heavy oil accumulation is part of an offshore discovery. A number of Iranian fields produce heavy oil.

Iraq

Oil seepages have been known and utilised in Iraq throughout historical time but are insufficient for serving as sources of synthetic oil. Although heavy oil fields are productive in the country, very little extra-heavy oil has been identified.

Israel

The extra-heavy oil that is known in Israel is located in the Dead Sea province. Natural bitumen occurs only as Dead Sea asphalt blocks, which occasionally rise to the surface.

Italy

Italy has 14 natural bitumen deposits and 31 extra-heavy oil deposits. The 269 million barrels of original reserves of extra-heavy oil in Italy are found in six separate basins, similar geologically to the Durres Basin of Albania. The most important of these is the Caltanisetta Basin, mostly offshore and including the Gela field. These fields are all found in the foredeep portion of the basins, where the sediments are thickest and most structurally disturbed. The viscous nature of the oil, the offshore environment, and the limited resources create challenges to economic development of these accumulations.

Kazakhstan

Although Kazakhstan possesses large resources of conventional and heavy oil, it contains little if any extra-heavy oil. It does have significant resources of natural bitumen in the North Caspian Basin. As with nearly all the large natural bitumen deposits, the geological setting, like that of the Western Canada Sedimentary Basin, is conducive to the development of natural bitumen. In the light of the very large resources of conventional oil and natural gas in this country, development of the bitumen as a source of synthetic oil is unlikely in the foreseeable future.

Kyrgyzstan

Little is known about these deposits except their location in the Fergana Basin and that they have yet to be evaluated.

Madagascar

Bemolanga is the only natural bitumen deposit in Madagascar. It is large and attempts at producing synthetic oil have thus far failed. A large heavy-oil deposit, Tsimiroro, has similarly been the subject of a number of unsuccessful production tests but no extra-heavy oil has been identified in the country.

Mexico

Mexico, with numerous heavy oil fields, contains very few extra-heavy oil reservoirs. The latter are small in resources and production. Oil seepages are common in the country, but no large natural bitumen deposits have been found.

Nigeria

Natural bitumen in place, possibly totaling as much as 38 billion barrels, is located in southwestern Nigeria, in the Ghana Basin. This extensive deposit has not yet been evaluated as a source of synthetic oil and its production will no doubt be delayed as long as Nigeria is a leading producer of conventional oil.

Peru

Peru contains numerous heavy oil deposits, mostly in the Oriente Basin. However, the recoverable oil from the two known extra-heavy oil accumulations of that country is relatively small.

Poland

With current technology, the two extra-heavy oil reservoirs of Poland are marginally economic.

Russian Federation

Extra-heavy oil has been identified in the Russian Federation in small amounts in the Volga-Urals and North Caucasus-Mangyshlak Basins (S.I. Goldberg, written communication). As is the case with many countries, accurate and timely data are insufficient for making estimates.

Information relating to natural bitumen deposits indicates that very large resources are present in the east Siberia platform in the Tunguska Basin (Meyer and Freeman, 2006). This is harsh terrain and only the Olenek deposit has been studied in sufficient detail to permit the estimation of discovered bitumen in place. The Siligir deposit has been frequently cited in reports of world bitumen deposits, but the primary source for these citations has not been located. It may be assumed that the estimate of more than 51 billion barrels for the basin is conservative. This area is so remote, and Russia's conventional oil and gas resources so great, that it is not likely that attempts will be made in the near future to exploit this natural bitumen. Most of the other Russian bitumen deposits are located in the Timan-Pechora and Volga-Urals Basins, which are analogous geologically to the Western Canada Sedimentary Basin. However, these deposits are scattered and the recoverable portions are not quantitatively large. The deposits in the Tatar Republic have been studied extensively and efforts to exploit them may be conducted in the future.

Switzerland

The Val de Travers natural bitumen deposit in Switzerland is small, but representative of many such occurrences in Western European countries. Most of these have been known for centuries and a few have been mined, mainly for road material.

Syria (Arab Republic)

The Babenna natural bitumen in deposit was mined for many years for asphalt. It is one of numerous such deposits throughout the Middle East, those in Syria and Iraq being especially prominent since antiquity. They are not regarded as potential commercial sources of synthetic oil.

Tajikistan

Little is known about the four bitumen accumulations except that three are located in the Amu-Darya Basin and the fourth is located in the Fergana Basin.

Tonga

The Tonga natural bitumen accumulation was found as a seep but has yet to be evaluated.

Trinidad and Tobago

Trinidad and Tobago is rich in heavy oil, but only 300 million barrels of oil in place is extra-heavy. The country has more than 600 million barrels of oil in place in natural bitumen deposits, including Asphalt (Pitch) Lake. All these deposits are located in the Southern Basin, which is small, highly faulted, but highly productive.

Asphalt (Pitch) Lake, at La Brea, contains a semi-solid emulsion of soluble bitumen, mineral matter, and other minor constituents (mainly water). It has been mined since at least 1815 but mostly for use as road surfacing material. The lake contains 60 million barrels of bitumen, a sufficient supply for the foreseeable future. Production is between 10 000 and 15 000 tonnes per year (equivalent to 60 000 to 92 000 barrels per year), most of which is exported. In combination with asphalt from refined crude oil, the product is used for road construction. In addition, it can be used in a range of paints and coatings and for making cationic bitumen emulsions. Production of these emulsions of bitumen, water, and soap began in late 1996 and the emulsions are now used widely throughout the industrialised world in place of solvent-based bitumen emulsions.

United Kingdom

Offshore the United Kingdom has two extra-heavy oil deposits. One is a discovery in the West of Shetlands Basin, for which few data are available. The other is the producing Piper field in the North Sea Graben, which contains oil between 8.7º and 37º API gravity.

United States of America

The United States was endowed with very large petroleum resources, which are to be found in nearly all the various types of geologic basins. The resources of extra-heavy oil and natural bitumen likewise are distributed in numerous geological settings. Geologically, about 80% of the discovered US natural bitumen is deposited in basins similar to the Western Canada Sedimentary Basin. Such basins possess ideal conditions for occurrences of degraded oil. However, the bitumen deposits of the United States are much smaller, much less numerous, but more scattered. About 98% of the reported extra-heavy oil is found in basins which evolved along the rift-faulted, convergent continental margin of California where the island arcs which originally trapped the sediments against the land mass to the east have been destroyed. Distillation of oil from Casmalia tar sands in California was attempted in 1923. Many tar sands deposits in the United States have served as sources of road asphalt, but this industry disappeared with the advent of manufactured asphalt tailor-made from refinery stills. The largest deposits in the lower conterminous 48 states are in Utah. During the 1980s US energy analysts studied criteria, both technical and economic, for supply of synthetic crude oil from tar sands and several tar sands pilot projects were started. With the decline in and stagnation of crude oil prices from the later 1980s to about 2000, there was little interest in pursuing these projects. The recent sustained increases in oil prices have revived this interest.

The extra-heavy oil accumulations in California account for about 97% of the extra-heavy oil produced to date. These are typically reservoirs found in large fields, multiple reservoir fields, and fields that may have already installed a thermal recovery operation for production of heavy oil in underlying reservoirs or overlying reservoirs.

Uzbekistan

Little is known about the eight natural bitumen occurrences in Uzbekistan except that six occur in the Fergana Basin and two are located in the Amu-Darya Basin. The single occurrence of extra-heavy oil is reported as part of the Khaudag deposit in the Amu-Darya Basin (S.I. Goldberg, written communication). Its size is unknown.

Venezuela

A small amount of the Venezuelan extra-heavy oil resource is found in the Maracaibo Basin, but the resources of worldwide significance lie in the Orinoco Oil Belt along the southern, up-dip edge of the Eastern Venezuela Basin. One natural bitumen deposit, Guanoco Lake, is found near the Caribbean coast on the north side of the Eastern Venezuela Basin. The deposit has been estimated to contain 62 million barrels of oil in place (Walters, 1974).

Four joint ventures for the exploitation of extra-heavy crude have been operating since 2001, and as of 2006 have an extra-heavy oil production capacity of 640 000 b/d. All the projects, in one way or another, involve production, transportation, and upgrading facilities. In 2001, Venezuela passed the new Hydrocarbons Law that increased royalties and required all new projects with foreign oil firm participation to be formed as joint ventures with PDVSA (Petróleos de Venezuela) as majority owner.

Venezuela, through PDVSA, started a reserves certification programme to increase the proved reserves in the Orinoco Oil Belt. The companies that participate in the certification programme will be considered first for upstream development. Participation in the programme has been by foreign national oil companies: Petrobras (Brazil), Petropars (Iran), CNPC (China) and ONGC (India). Petrobras and PDVSA have already established a joint venture to develop the Carabobo 1 block. The project is supposed to produce 200 000 b/d of extra-heavy oil at its peak. An offsite upgrade facility is included. Project investment costs are expected to be $4 billion. Some of the partnerships of currently-operating extra-heavy oil projects are seeking to increase reserves and production at their projects. However, the Venezuelan government has announced its intention to nationalise the Orinoco projects.

In the early 1980s Intevep, the research affiliate of the state oil company PDVSA, developed a method of utilising some of the hitherto untouched potential of Venezuela's extra-heavy oil resource. The extra-heavy oil (7.5-8.5º gravity API) was extracted from the reservoir and emulsified with water (70% natural bitumen, 30% water, <1% surfactants). The resulting product was called Orimulsion®. Initial tests were conducted in Japan, Canada and the United Kingdom, and exports began in 1988. Bitúmenes del Orinoco S.A. (Bitor), a PDVSA subsidiary, operated a plant at Morichal in Cerro Negro with a capacity of 5.2 million tonnes per year. In 2005 PDVSA announced it would cease Orimulsion® production because it was more profitable to sell the extracted oil as feedstock to extra-heavy oil upgraders. In 2006, PDVSA and CNPC (Chinese National Oil Company) initiated the Sinovensa project, to supply two power plants in China and to meet some of PDVSA's commitments to supply Orimulsion®. However, in September 2006 the Minister of Energy and Petroleum announced that the Sinovensa operation would cease production at the end of the year.

5. Natural Gas

COMMENTARY

Natural Gas Market Developments: The Way Ahead

Natural gas, having for decades been reserved primarily for the nobler industrial uses, and basically possessing no captive market, has now become the fuel of choice in many key consuming sectors. Over the years, when available at competitive prices, gas has seized emerging growth opportunities, strengthening its position in the residential and industrial sectors, and even more intensively in the power sector.

Market expansion, technological innovation and supply-source diversification are now reshaping the global energy landscape. Driven by annual economic growth estimated to average 3.4% during the period 2004-2030, world energy demand could grow by about 1.6% p.a. on average by 2030, according to the International Energy Agency (WEO 2006). This means that by then the world will need about half as much more energy than is used today. Fossil fuels are assumed to remain the dominant sources of primary energy, accounting for close to 83% of the overall increase between 2004 and 2030.

These potential developments, whilst undoubtedly offering the gas industry new growth opportunities, also imply a number of challenges that the industry will have to meet in order for gas to make a major contribution to the energy industry of the 21st century.

Natural Gas: A Successful Energy

Over the past decades, natural gas use grew unabated, demonstrating its major role as a world-scale energy source. It currently accounts for 23.5% of the world energy mix and ranks third, behind oil and coal. This expansion was sparked by many essential breakthroughs.

Technological breakthroughs. While the gas industry largely benefitted from technological innovation in the upstream oil industry, specific new technologies spectacularly extended the possibilities of transporting this energy source, hamstrung by the fact that it is necessary to transport a volume 1 000 times larger than oil for the same energy content, making gas transportation at least five times more expensive. Natural gas liquefaction, long-distance pipelines and deep offshore pipe-laying tremendously improved gas supply.

Gas flows between countries and continents accordingly grew unchecked, accompanied by the installation of new, sophisticated and costly transport chains. In 2006, international flows were close to 886 bcm, covering about 30% of marketed production.

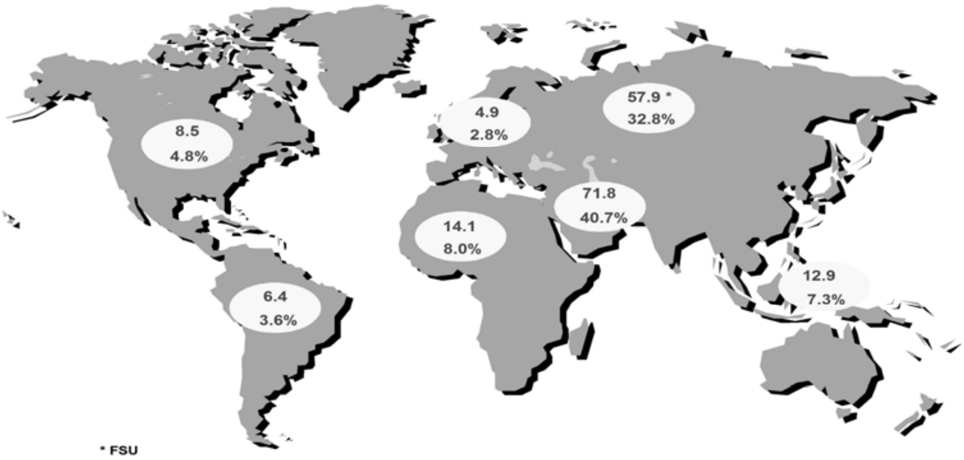
Downstream, combined-cycle gas-fired power plants have revolutionised the power sector, transforming it into the locomotive for world gas growth. Besides technical and economic performance, produced by efficiencies as high as 58%, combined-cycle power plants also offer compact facility design, a reduction in construction time and investment, plus better space integration.

Gas price competitiveness. The competitiveness of gas prices has been sustained by the efforts made by the industry to reduce costs at every stage in the chain. The use of advanced technologies in seismic imaging and drilling, as well as improvements in capital expenditure and operating costs, were responsible for a steady 2.5% p.a. fall in exploration & production costs until relatively recently. The industry also very significantly improved liquefied natural gas (LNG) competitiveness, cutting costs at all stages of this complex chain. Greatly improved overall design of LNG projects, in tandem with the characteristics of gas supply in the upstream sector and those of regasification plant outlets, optimised project construction, and a systematic attempt to shorten construction deadlines helped to cut costs. As an illustration, the average unit investment cost for a liquefaction plant dropped from US$ 250/t/yr in the mid- to late-1990s to US$ 200/t/yr entering the new millennium.

The netback market value approach (pricing gas in relation to competing fuels in the end-user market), which has traditionally been the basis of gas pricing throughout the gas chain in major consuming countries, in Europe for instance, has also played a role in securing gas market growth.

Exploration successes. Since 1980, proven world natural gas reserves have grown at an annual average of 3.4% (compared with 2.4%

Figure 5-1 Proved natural gas reserves as at end-2005 (tcm and % of world)
Source: SER



for oil), due to an impressive string of gas exploration successes and better assessments of existing fields. Hence the volume of proven gas reserves more than doubled over the period, from about 77 tcm in 1980 to some 177 tcm in 2006, growing at a roughly linear rate over time in the range of 4 tcm/yr. The life duration of proved reserves, as a ratio to current consumption, is in excess of 56 years.

Assets for Future Gas Market Growth

Less-energy-intensive economies, stringent pressures to reduce the environmental impact of fossil fuels, and political and fiscal measures to increase the share of renewable energy in the global energy mix, have gradually combined to alter the growth prospects of each of the primary energies, and, consequently, their respective weight in the energy balance. Although natural gas is a flexible energy, ideally adapted to a number of uses, these ongoing developments are undoubtedly influencing its future growth potential, particularly in the OECD countries.

Nevertheless, while recent years have seen a globally downward revision of growth prospects for energy demand, natural gas is still the fossil fuel with the strongest potential. Several factors underlie a presumption of steady growth in gas demand of the order of 2% p.a. on average between now and 2020. With anticipated consumption of about 3 850 bcm by then, natural gas would accordingly account for about a quarter of world primary energy demand.

A significant growth potential. Non-OECD countries certainly harbour the largest potential for growth. Driven by steady population growth and strong economic activity, total energy needs should climb at quite a smart pace, providing natural gas with new opportunities for market development. The fast-growing economies in Asia (including China and India), the Middle East, Africa and even Latin America, promise gas demand growth rates of 3-4% p.a. by 2020.

The industrial and power generation sectors will be the powerhouse for future gas requirements. In some Asian countries, proactive government policies have fostered significant structural shifts in primary energy supply for power generation, the share of natural gas being boosted to reduce dependence on imported furnace oil, as in Pakistan. Also in Asia (India, Indonesia), fertiliser production (urea, ammonia) will also require growing volumes of natural gas, both as fuel and as raw material. In the Middle East, gas will be increasingly used in seawater desalination plants and in industry in general. In Africa, besides a growing requirement from the power sector, gas network extensions open up broader country-wide developments, such as in Algeria and Egypt. In Latin America, with the exception of Argentina, gas market developments are recent, indicating that gas still has significant potential for growth (Brazil, Chile, Peru).

In the OECD countries of North America and Europe, where the gas share is 24-25% already, The abundance of gas reserves already discovered, and the prospects for a large yet-to-find potential, give natural gas a lifetime probably in excess of 130 years, at the current rate of consumption.

this source of energy should continue to grow, albeit at rather moderate annual rates of 1.6% and 2% respectively.

In the United States and Europe, high gas prices have already significantly impacted on demand. In the United States, they prompted the largest industrial users to turn to alternative energies, as in the past, when they chose natural gas because it was a cheaper source of energy. In Europe, high gas prices have started to stimulate competition between the different sources of energy. In the power sector, where substitution of one energy by another can be fairly rapid, power producers, in the United Kingdom for instance, have recently favoured coal, an abundant resource which, despite recent price increases, still remains cheaper at the plant gate than natural gas, whose price is often indexed to oil products.

From a sectoral standpoint, the power sector should further consolidate its position, absorbing about 37% of marketed gas each year by 2020. While industry should maintain its current 25% share, the residential and tertiary sectors are likely to decline in importance.

A more environmentally-friendly energy. In the world energy mix, natural gas is undeniably the fossil energy whose combustion has the lowest environmental impact. Although its contribution to greenhouse gas emissions (CO_2 in particular) cannot be discounted, it definitely plays a minor role in the emission of pollutants: about 30% less than oil products and 50% less than coal. In a context of increasingly stringent political and fiscal measures over the course of time, in order to reduce the negative environmental impact of the energy industries, the growing use of natural gas can only favour the fulfilment of Kyoto commitments.

Immense untapped potential. Estimates of the volume of gas remaining to be found have been consistently and significantly underestimated. Moreover, gas exploration still stands at a significantly lower degree of maturity than oil.

The abundance of gas reserves already discovered, and the prospects for a large yet-to-find potential, give natural gas a lifetime probably in excess of 130 years, at the current rate of consumption (2 930 bcm in 2006). Because interest in natural gas was very late in developing, many territories have been only partially explored, if at all. As the recent period suggests, specifically gas-targeted exploration most often yields very prolific discoveries, as witnessed in Bolivia and Egypt. Additionally, improvements in transportation economics are gradually providing access to a potential of ‘stranded’ gas, remote from consuming zones, onshore and offshore, currently estimated at 30-35 tcm, making it marketable at a competitive price. New frontier areas for exploration are also opening up, in deeper and more complex horizons, fold-belt provinces and deep sedimentary basins, technology permitting. The Arctic basins in particular present very high potential for hydrocarbons, especially gas. While exploration in fold belts has hitherto focussed on the shallowest objectives, deep exploration has been little undertaken, leaving hopes of future

Gas technologies consequently represent a key element in the commercialisation of natural gas.

major gas discoveries. Accordingly, additional gas resources of 170-220 tcm, representing at least as much as current proven reserves, are probably still classed as unproven or yet-to-find.

Furthermore, conventional gas resources must be augmented by the large potential of unconventional gas. Coal-bed methane (CBM) resources represent an additional volume estimated at 100 to 250 tcm. Gas shales and tight gas sands resources also harbour very high and still largely unidentified potential. The industry has mastered the recovery of coal-bed methane and gas from tight sands or shales. In the United States for instance, CBM and tight gas production currently account for about 30% of total gas produced every year. Although no technique to develop and produce hydrate potential (20 000 to 25 000 tcm offshore?) has been tested on an industrial scale, hydrates are also often touted as a valid alternative, offering a cleaner energy source than hydrocarbons.

Technologies open up supply routes. The distribution of gas reserves is far from in harmony with the size and growth of the markets. Although recent gas discoveries are strewn just about everywhere, affecting all continents and prompting reassessments of reserves in almost all regions, the Former Soviet Union and the Middle East together still possess 73% of proven reserves, including most of the largest fields. As for the OECD countries, they have no more than 10% of gas reserves, while they consume about 50% of the volume produced worldwide every year. This creates growing regional imbalances between production and demand, at the continental level, and even more so, at the country level.

The steadily increasing length of haul between the world's gas-rich regions and consumer zones accordingly foreshadows a powerful expansion in international trade, at an annual rate of about 3.5%, to 1 430 bcm by 2020. Flows could then account for about 35-37% of marketed production.

Gas technologies consequently represent a key element in the commercialisation of natural gas. Several options, either traditional (LNG, pipeline) or emerging (Gas to Liquids [GTL], Compressed Natural Gas [CNG], Gas to Wire [GTW] etc.) can be considered. However, the most suitable export route has to be selected by considering issues such as the comparative economics (field output target, distance to consumer, etc.) and the end-user markets.

- **Pipeline flows dominate international gas trade.** Because pipeline technology has been relatively more straightforward, easier and more economic to develop, both onshore and offshore - even over long distances - pipeline deliveries between countries and nearby continents have largely dominated international gas trade. Currently 76% of international flows are in gaseous form by pipelines. However, the bulk (about 70%) of the 675 bcm is transported by international pipelines in North America and in Europe. While a densely interconnected network progressively helped to integrate

Canadian, American and Mexican supplies in the vast American market, the construction of trans-European networks gathered speed between 1970 and 1990, following the first oil shock. These pipelines laid the foundations for an extensive interconnected network stretching over more than a million kilometres across Europe, from Siberia to Ireland, from Norway to Spain, from Algeria to Portugal and Central Europe.

With its 45% dependence on external suppliers, Europe currently has an annual pipeline import capacity of about 360 bcm, including 100 bcm from Norway, 200 bcm from Russia, 40 bcm from Algeria, and about 8 bcm each from Libya and Iran.

With the exception of Latin America, where regionally-traded volumes amount to about 17 bcm/yr, the development of intra- and inter-regional networks in other parts of the world is still rather limited. In Asia, the installation of an intra-regional transport network is relatively recent, restricted to Singapore's import of gas from Malaysia and Indonesia, and the supply of 9 bcm/yr produced from the Yadana and Yetagun offshore Myanmar fields and transported to Thailand. In the Middle East, gas flows have been confirmed to within the United Arab Emirates.

Although the rebalancing of natural gas markets via gas pipelines could increasingly face limitations – owing to technical, economic and even political reasons in relation to transit issues, a number of new long-distance pipelines are on the drawing board in all regions. Europe hosts the largest number of projects, with large-capacity pipelines (20 bcm/yr or more) aimed at exporting Russian gas to Northern Europe (NordStream via the Baltic Sea) and Southern Europe (BlueStream II), as well as delivering Central Asian or Middle East gas to Central Europe (Nabucco project). To the north, the Langeled pipeline, supplying gas from the Norwegian Ormen Lange field to the United Kingdom, will be fully commissioned by the end of 2007. From Algeria, two new 8 bcm/yr capacity pipelines should be built in the short-to-medium-term to establish a direct link to Spain (Medgaz) and a route to Italy via Sardinia (Galsi).

In Africa, planned export pipeline schemes include a line from Nigeria to Algeria and another for the expansion of Egyptian supplies to Jordan, Lebanon and Syria. The latter proposed line also involves a potential extension to Turkey in a later phase. In the Middle East, the Dolphin project is due to start delivering Qatari gas to the United Arab Emirates

Figure 5-2 LNG flows in 2005: 188.8 bcm
Source: Cedigaz

Data in billion cubic metres

shortly. Feasibility studies are also under way for building a line from Iran to India, through Pakistan.

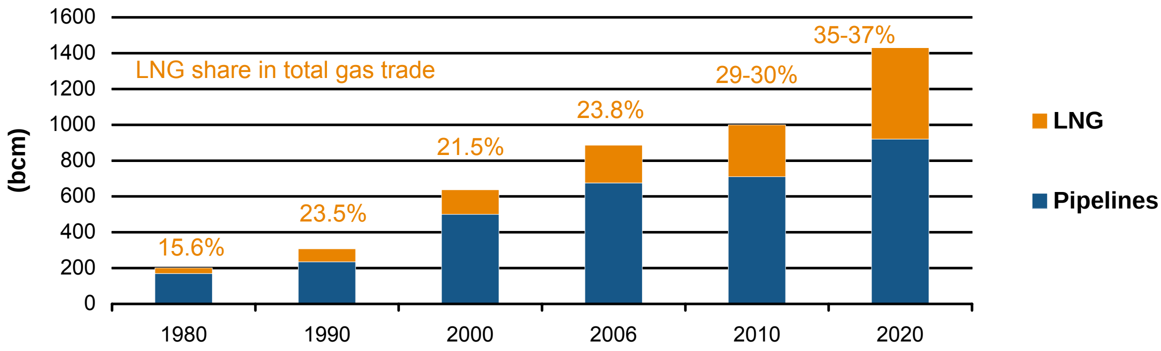
Besides the long-distance pipeline project from Alaska to the lower-48 US States, new schemesare also planned in northern Latin American countries (between Venezuela and Colombia), as well as in the Caribbean.

In Asia, long-distance pipelines are being considered to deliver Central Asian gas to China, and from Russia's Yakutia to South Korea.

Over the past decade, significant technological achievements have been made in deep-offshore pipe-laying, with the construction of the BlueStream linking Russia to Turkey across the Black Sea at a water depth of 2 200 metres. In the years ahead, technological advances should provide pipeline trade with new opportunities for growth, while further cutting transportation costs. To fulfil this objective, offshore pipe-laying has led to the introduction of higher pressures, while the use of high-tensile steels (X80, X100 or X120) emerges as the most appropriate option for onshore transportation.

- **LNG drives gas market globalisation.** In recent decades, developments in the LNG business have been impressive in many respects. However, the most spectacular growth undoubtedly occurred from the mid-1990s onwards. New players entered the industry, which now numbers 13 exporting and 17 importing countries. Liquefaction capacities more than doubled, from 114 bcm/yr (86 mt/yr) in 1996 to about 243 bcm/yr (183 mt/yr) in 2006. Simultaneously, regasification capacities grew rapidly from 322 to 496 bcm/yr (242 to 373 mt/yr). The LNG tanker fleet expanded massively, with

Figure 5-3 The increasing role of world gas trade
Source: Cedigaz



some 220 ships in service last year, compared with 90 ships in 1995. The companies involved have diversified, with power utilities joining their ranks as markets reshape.

More generally, asset acquisitions and shareholding diversifications along the overall chain have largely restructured the traditional

LNG model. Competition has intensified as a result of market deregulation procedures. Inter-regional trade has expanded rapidly, driven by price arbitrage between the Atlantic and Pacific basins. Contractual forms have diversified and destination clauses have largely been discarded. Last but not least, the industry has also established new benchmarks, cutting costs significantly at all stages in the chain, commensurately improving project economics and LNG competitiveness.

The increasing need for market flexibility, diversification of sources, and reinforced supply security, are some of the reasons why LNG will increasingly play a key role in rebalancing gas markets worldwide. Cedigaz anticipates a sustained growth of world LNG flows, rising from 211 bcm in 2006 to about 510 bcm/yr by 2020, an annual average rate of 6.5%. With these growth patterns, LNG's share of total world gas trade could soar to about 36%, from the current 22.5%.

Although likely to display glaring contrasts, markets East and West of Suez harbour significant growth potential for LNG.

With an increasingly diversified portfolio of supply sources, LNG demand East of Suez could reach 220 bcm/yr by 2020. With predicted annual growth of about 3.6%, the leading position of markets East of Suez in global LNG demand is set to weaken rapidly to approximately 45% of the world total in 2020 (64% in 2006). While Japan and South Korea are likely to continue to provide significant impetus to LNG tanker trade in the region, China and India will import increasing volumes to supplement domestic gas.

With most gas-short OECD countries concentrated in the Atlantic Basin, West of Suez markets, where LNG demand has grown 70% in the past five years compared with 25% in the Pacific Basin, harbour the strongest growth potential. The area could see approximately 9.5% growth per year by 2020 to about 270 bcm (76 bcm in 2006). From the turn of the next decade - while US gas production should continue to grow as a result of unconventional gas developments - the rapid decline of Canadian production, combined with increasing local gas needs, should generate a massive call on LNG suppliers to restore the North American market balance. Europe's growing dependence on external supplies could reach some 60% by 2015. To cover part of the supply gap, traditional operators and new entrants are actively developing and planning new import capacities. While new import pipeline capacities from Norway, Algeria and Russia will help secure a portion of additional demand, Europe will need ever more LNG. Potential LNG receiving capacities amounting to 153 bcm/yr are being built and planned.

On the supply side, since 2000, additional liquefaction capacity of about 88 bcm/yr has started producing LNG, half of it in the Atlantic Basin. The Pacific Basin still hosts 41% of the world's capacity.

The LNG industry is currently going through a sellers' market. Stimulated by the discovery of large gas resources in new areas (Australia, West Africa, Egypt, Peru) and the growth potential of LNG demand, national and international companies are investing massively in the construction of new trains at existing facilities and grassroots plants. Liquefaction capacity is therefore slated to climb sharply to some 350 bcm/yr by 2010, growing at an average annual rate of 8%.

A radical shift in the location pattern of liquefaction capacities is already clearly under way, and by 2010 the Middle East and Pacific Basin should equally share about 70% of the world total. Although new projects are due for commissioning in the coming months in the Atlantic Basin, at least 57% of total new capacity will be located in Qatar and Yemen. Qatar already counts as the world's largest LNG exporter, Indonesia relinquishing its leadership. The Pacific Basin's share is bound to shrink further, owing to the rapid growth of new capacity outside this basin and the anticipated drop in Indonesia's export potential, with which other countries in the region will have to contend. The Indonesian Government's determination to boost gas supplies to its domestic market will limit the nation's LNG export potential.

On the technological front, the industry is intensifying its economy drives, improving project economics by economies of scale. With regard to liquefaction, very large capacity trains are in the offing, as shown by Qatar's Qatargas II and RasGas II 10.4 bcm/yr per train projects, compared to the current world's biggest (RasGas 3rd Train) with a capacity of 6.3 bcm/yr.

Major advances are also under way for the new generation of LNG tankers. Standard tanker size has already increased to 155 000 m^3, and several orders have already been placed for ship capacities of 210 000 and even 260 000 m^3. Improved insulation systems and the adoption of more efficient propulsion modes are among major technological improvements.

The trend is towards larger regasification plants, up to 9 bcm/yr, as well as new concepts for offshore receiving terminals (single-point mooring, gravity-based structures, floating storage regasification unit, floating converted carrier) to comply with stringent environmental regulations.

Although each export project has its own specificities, liquefaction plus sea transport often emerges as the most competitive option for commercialising large gas reserves when distances from producer to end-user exceed about 3 200 km. However, in the longer term, few countries will be endowed with sufficient and suitably-located gas resources capable of durably sustaining export capacity and, in most cases, a local market. Since offshore areas, where about 40% of proven reserves are located, offer promising prospects for new gas discoveries, new transportation concepts will become the key to realising reserves from smaller, remote fields. Offshore liquefaction plants are emerging as one option, although, up to now, they have not become commercial. Mini-LNG plants, which are already used for peak-shaving applications in a number of countries, are also part of the possibilities, although the economics have not proved favourable so far.

- **New emerging transportation technologies.** An alternative way to export gas, while cutting transportation costs, which remain a major hurdle for the industry, is to convert it into liquid fuels for the transportation sector or chemicals (oxygenates, methanol and DME [dimethylether]). A new GTL plant was recently commissioned in Qatar. However, GTL projects are highly energy- and capital-intensive, and rising gas prices and investment costs currently make these projects rather uneconomic, with the breakeven price of crude now being around US$ 30/bbl compared to US$ 20/bbl a few years ago.

  CNG technology provides another alternative to transporting small volumes of gas over shorter distances, at pressures of about 200 bar. This option is aimed at utilising offshore reserves that cannot be produced, owing to a lack of pipeline availability or because the economics do not make LNG viable. CNG can accommodate small gas fields, even of 1 to 3 bcm. Coselle and VOTRANS are two would-be commercial, high-pressure gas storage and transport technologies for CNG.

  Transportation technologies enabling gas to enter new outlets also include the conversion of gas into electricity and then its transmission by wire over long distances. Although a number of obstacles still remain to be overcome before this option develops

Approximately 44% of total proven reserves is concentrated in some twenty mega and supergiant fields.

significantly, recent advances in semiconductors and insulating materials have reduced transmission costs for high-voltage DC electricity.

Stakes and Challenges

The gas industry is experiencing a multitude of changes. While a truly global gas market is still a long way off, the increasing inter-regionalisation of flows is definitely opening new trends. The anticipated development of spot and short-term LNG transactions, which accounted for about 15% of world LNG trade in 2006, will play a major role in the gradual establishment of an international gas price. Price arbitrage, consisting in directing LNG cargoes to the highest-value market, was initially concentrated in the Atlantic Basin (US and European markets). The move now inter-links both Atlantic and Asia-Pacific basins, gradually setting a more uniform price for the large importing countries.

Market liberalisation, and the consequent twinning which develops amongst players in the electricity and gas industries, strengthen competition in the markets. The advent of trading hubs, in Europe in particular, is driving the development of a spot market with its own price specificities according to the market structure. Such prices are more volatile than those for gas purchased under long-term contracts, which are largely indexed to oil or oil products.

In addition to these developments inherent in market restructuring, the industry will have to contend with a number of major issues and challenges.

Gas reserves are geographically concentrated. While about 73% of gas reserves are concentrated in two areas – the Middle East and the CIS - the geopolitical distribution of gas reserves is rather similar to that of oil. With nearly 90 tcm, the OPEC countries have about half of total reserves, compared with 75% for oil. The CIS enjoys a more advantageous situation for gas, with 33% of reserves against only 10% of oil reserves. In the OECD countries, the situation is barely different for either energy resource, with less than 10% of gas reserves and 7% of oil reserves. By 2020, non-OECD countries could account for about 88% of world gas trade, including 58% for OPEC countries.

Approximately 44% of total proven reserves is concentrated in some twenty mega and supergiant fields. Out of these, the world's largest non-associated gas field - North Field/South Pars - straddling Qatari and Iranian waters, accounts for some 49%.

This concentration of gas wealth naturally raises questions of security of supply, of transit, of the potential implementation of an organisation of gas-exporting countries (OGEC) and of assets nationalisation strategies. To address these issues, consuming countries will increasingly respond by diversifying supplies.

Gas competitiveness and alternative energies. The future expansion of energy demand will inevitably entail a broadening of the portfolio of available energy sources. Although

Natural gas will act as a gateway towards the energies of the future, including hydrogen.

natural gas is globally more environment-friendly than most competing sources, its price, should it be maintained at rather high levels, could shrink its anticipated growth potential. Coal, being abundant and currently available more cheaply, could benefit from the situation, particularly in the power sector. However, although new coal-fired plants with carbon capture potentially represent a threat to natural gas, such technological innovations could also translate into higher costs, forestalling a massive trend to this option.

In the longer run (beyond 2020), nuclear power remains in the forefront. Although complex cost factors question just how attractive nuclear power really is against the traditional and emerging power-generation technologies, this option may earn more credit in some big consuming countries.

Renewable sources will also undoubtedly draw increasing attention, as shown by the political and fiscal measures implemented in a large number of OECD countries.

Rising costs throughout the industry. The recent high energy prices have boosted activity in all sectors. Combined with sustained activity to rebuild facilities in the Gulf of Mexico after hurricanes Katrina and Rita, all sectors of the industry are going through hard times coping with rising costs. Booming upstream operations, labour shortages and rising raw material costs are the key elements in such a trend. Total average oil and gas production costs rose by an estimated 25.6% between 2004 and 2005 to US$ 6.87/boe, according to the US Department of Energy. In addition, the DOE also shows that average worldwide finding costs for the Financial Reporting System companies rose 17% in the 2003-2005 period, an increase of US$ 1.55/boe.

With regard to the LNG chain, the abundance of orders placed for new liquefaction plants and LNG tankers is pushing costs higher and cramping anticipated profits. Today, despite the building of much larger liquefaction trains, production costs per ton of LNG produced have more than doubled since 2004, and are now approaching US$ 450/t/yr. The limited number of licensors, contractors and equipment manufacturers in such a dynamic business, together with rising raw material prices (of steel in particular), explain this pattern. The need to comply with environmental and safety requirements has also spurred higher investment requirements in liquefaction and regasification plants (offshore terminals). The impressive number of LNG tankers currently on order, in a handful of shipyards - more than 140 (all sizes combined) - consequently means higher prices. The price of standard-size (about 158 000 m^3) ships has risen significantly, from about US$ 155 million in 2003 to about 210 million today.

While rising costs do not apply to those projects currently under construction, for which investment decisions had already been taken in 2004, they clearly delay FID on future plants due to be built from 2010 onwards. As a consequence, some slippage can be expected between initial and actual facility start-up dates.

Reducing CO_2 emissions. Protection of the environment is growing in importance and because combustion of gas emits CO_2 (although much less than other fossil fuels), the gas industry has to comply with commitments signed in accordance with the Kyoto Protocol.

Meeting new environmental standards along the chain (carbon capture, less flaring, Health & Safety Management System Guidelines, etc.) means costly developments for the industry in the short-to-medium term, as new infrastructure investments have to be made. However, long-term benefits are immense. Energy resources are quantitatively limited by nature and thus it is all the more essential to secure the best resources management.

Too great a reliance on fossil fuels may indeed rapidly amplify the risks of climate change. For the gas industry, it is accordingly essential to eliminate flaring. Every year, more than 115 bcm are flared worldwide, including about 40 bcm in Africa. According to the Global Gas Flaring Reduction public-private partnership (GGFR, a World Bank-led initiative), gas flaring adds about 390 million tonnes of CO_2 in annual emissions. This is more than the potential yearly emission reductions from projects currently submitted under the Kyoto mechanisms. A reduction in gas flaring can contribute to lower CO_2 emissions, while, at the same time, enhancing energy security by increasing available supplies.

Conclusion

Natural gas will act as a gateway towards the energies of the future, including hydrogen. Technology will undoubtedly play a major role in this process. Innovating technologies, combining renewable energies (solar energy for instance) and natural gas will increasingly contribute to the response to sustainability development issues.

However, in the years ahead, the pace of growth in the gas market will remain very closely conditioned by the industry's ability to invest massively, to replace existing systems and to build new infrastructure and production capacity. Closer cooperation between all the players along the gas chain will accordingly be essential.

Marie-Françoise Chabrelie
Cedigaz

DEFINITIONS

Natural gas is a mixture of hydrocarbon and small quantities of non-hydrocarbons that exists either in the gaseous phase or is in solution in crude oil in natural underground reservoirs, and which is gaseous at atmospheric conditions of pressure and temperature.

Natural gas liquids (hydrocarbons that exist in the reservoir as constituents of natural gas but which are recovered as liquids in separators, field facilities or gas-processing plants) are discussed in Chapter 2 – Crude Oil and Natural Gas Liquids.

Proved amount in place is the resource remaining in known natural reservoirs that has been carefully measured and assessed as exploitable under present and expected local economic conditions with existing available technology.

Proved recoverable reserves are the volume *within* the proved amount in place that can be recovered in the future under present and expected local economic conditions with existing available technology.

Estimated additional amount in place is the volume *additional to* the proved amount in place that is of foreseeable economic interest. Speculative amounts are not included.

Estimated additional reserves recoverable is the volume *within* the estimated additional amount in place that geological and engineering information indicates with reasonable certainty might be recovered in the future.

Production - where available, gross and net (marketed) volumes are given, together with the quantities re-injected, flared and lost in shrinkage (due to the extraction of natural gas liquids, etc.).

Consumption - natural gas consumed within the country, including imports but excluding amounts re-injected, flared and lost in shrinkage.

R/P (reserves/production) ratio is calculated by dividing proved recoverable reserves at the end of 2005 by production (gross less re-injected) in that year. The resulting figure is the time in years that the proved recoverable reserves would last if production were to continue at the 2005 level.

As far as possible, natural gas volumes are expressed in standard cubic metres, measured dry at 15^{o} C and 1 013 mb, and the corresponding cubic feet (at 35.315 cubic feet per cubic metre).

NOTE:

The quantifications of reserves and resources presented in the tables that follow incorporate, as far as possible, data reported by WEC Member Committees. Such data will reflect the respective Member Committees' interpretation of the above Definitions in the context of the reserves/resources information available to them, and the degree to which particular countries' terminology and statistical conventions are compatible with the WEC specifications.

TABLES

Table 5-1 Natural gas: proved recoverable reserves at end-2005

	billion cubic metres	billion cubic feet
Algeria	4 504	159 069
Angola	113	4 000
Benin	1	40
Cameroon	150	5 300
Congo (Brazzaville)	91	3 200
Congo (Democratic Rep.)	1	35
Côte d'Ivoire	42	1 497
Egypt (Arab Rep.)	1 894	66 900
Equatorial Guinea	73	2 578
Ethiopia	25	883
Gabon	30	1 059
Ghana	24	848
Libya/GSPLAJ	1 491	52 655
Morocco	2	60
Mozambique	127	4 500
Namibia	21	750
Nigeria	5 150	181 872
Rwanda	57	2 000
Senegal	11	388
Somalia	6	200
South Africa	10	362
Sudan	113	3 991
Tanzania	24	846
Tunisia	92	3 257
Total Africa	**14 052**	**496 290**
Barbados	N	5
Canada	1 633	57 654
Cuba	71	2 500
Guatemala	3	109
Mexico	412	14 557
Trinidad & Tobago	532	18 780
United States of America	5 866	207 170
Total North America	**8 517**	**300 775**
Argentina	439	15 502
Bolivia	740	26 133
Brazil	306	10 821
Chile	98	3 460
Colombia	140	4 932

Table 5-1 Natural gas: proved recoverable reserves at end-2005

	billion cubic metres	billion cubic feet
Ecuador	10	345
Peru	338	11 928
Venezuela	4 315	152 384
Total South America	**6 386**	**225 505**
Afghanistan	50	1 750
Armenia	176	6 215
Azerbaijan	1 350	47 675
Bangladesh	436	15 397
Brunei	340	12 007
China	2 350	82 990
Georgia	8	300
India	1 101	38 882
Indonesia	2 754	97 260
Japan	51	1 808
Kazakhstan	3 000	105 945
Kyrgyzstan	6	200
Malaysia	2 480	87 581
Myanmar (Burma)	485	17 128
Nepal	N	N
Pakistan	807	28 507
Philippines	100	3 532
Taiwan, China	71	2 507
Tajikistan	6	200
Thailand	304	10 743
Turkey	15	523
Turkmenistan	2 860	101 000
Uzbekistan	1 850	65 333
Vietnam	365	12 890
Total Asia	**20 965**	**740 373**
Albania	2	71
Austria	15	530
Belarus	3	100
Bulgaria	1	39
Croatia	27	939
Czech Republic	4	141
Denmark	82	2 896
France	10	341
Germany	178	6 283
Greece	1	35
Hungary	67	2 369

Table 5-1 Natural gas: proved recoverable reserves at end-2005

	billion cubic metres	billion cubic feet
Ireland	10	350
Italy	170	6 004
Netherlands	1 256	44 356
Norway	2 358	83 273
Poland	75	2 632
Romania	121	4 269
Russian Federation	47 820	1 688 763
Serbia	48	1 700
Slovakia	15	530
Slovenia	N	N
Spain	3	90
Ukraine	787	27 804
United Kingdom	481	16 987
Total Europe	**53 534**	**1 890 502**
Bahrain	92	3 249
Iran (Islamic Rep.)	26 740	944 323
Iraq	3 170	111 949
Israel	34	1 200
Jordan	15	513
Kuwait	1 586	56 010
Oman	829	29 276
Qatar	25 633	905 240
Saudi Arabia	6 848	241 837
Syria (Arab Rep.)	298	10 524
United Arab Emirates	6 071	214 397
Yemen	479	16 916
Total Middle East	**71 795**	**2 535 434**
Australia	755	26 650
New Zealand	30	1 048
Papua New Guinea	428	15 115
Total Oceania	**1 213**	**42 813**
TOTAL WORLD	**176 462**	**6 231 692**

Notes:

1. The relationship between cubic metres and cubic feet is on the basis of one cubic metre = 35.315 cubic feet throughout
2. Sources: WEC Member Committees, 2006/7; *Oil & Gas Journal*, 19 December, 2006; Cedigaz; *Annual Report 2005*, OAPEC; *World Oil*, September 2006; national sources

Table 5-2 Natural gas: resources at end-2005

	Proved amount in place	Estimated additional amount in place	Estimated additional reserves recoverable	Proved amount in place	Estimated additional amount in place	Estimated additional reserves recoverable
	(billion cubic metres)			(trillion cubic feet)		
Africa						
Algeria	6 080			214.7		
Cameroon	187	677		6.6	23.9	
Côte d'Ivoire	58			2.0		
Ethiopia	113			4.0		
Namibia	40	113		1.4	4.0	
South Africa	15	28	19	0.5	1.0	0.7
Tanzania	44			1.6		
North America						
Canada	1 929			68.1		
Mexico		430			15.2	
Trinidad & Tobago	532	152	43	18.8	5.4	1.5
South America						
Argentina			249			8.8
Brazil			148			5.2
Peru			193			6.8
Asia						
India	1 595			56.3		
Indonesia	696			24.6		
Turkey	21			0.7		
Europe						
Austria	32			1.1		
Bulgaria			1			N
Croatia	27			0.9		
Czech Republic	41		2	1.4		0.1
Denmark	564	53	45	19.9	1.9	1.6
France	52			1.8		
Germany			64			2.3
Hungary	174	41-132	29-93	6.1	1.4-4.7	1.0-3.3
Italy		120-200			4.2-7.1	
Netherlands	1 510	180-440		53.3	6.4-15.5	
Poland	121	30		4.3	1.1	

Table 5-2 Natural gas: resources at end-2005

	Proved amount in place	Estimated additional amount in place	Estimated additional reserves recoverable	Proved amount in place	Estimated additional amount in place	Estimated additional reserves recoverable
	(billion cubic metres)			(trillion cubic feet)		
Romania	630	71	22	22.3	2.5	0.8
Russian Federation	8 426	39 400	9 037	297.6	1 391.4	319.1
Ukraine	1 021	357	169	36.1	12.6	6.0
United Kingdom	894	362	362	31.6	12.8	12.8
Middle East						
Israel	48	113	11	1.7	4.0	0.4
Jordan	17			0.6		
Syria (Arab Rep.)	598		12	21.1		0.4
Oceania						
New Zealand	159	31		5.6	1.1	

Notes:

1. The data on resources are those reported by WEC Member Committees in 2006/7. They thus constitute a sample, reflecting the information available in particular countries: they should not be considered as complete, or necessarily representative of the situation in each region. For this reason, regional and global aggregates have not been computed
2. Sources: WEC Member Committees, 2006/7

Table 5-3 Natural gas: 2005 production

	Gross	Re-injected	Flared	Shrinkage	Net	Net	R/P ratio
	(billion cubic metres)					(billion cubic feet)	
Algeria	192.8	87.6	3.6	14.3	87.3	3 083	42.8
Angola	8.5	1.2	6.3	0.2	0.8	28	15.5
Cameroon	1.2		1.1		0.1	5	> 100
Congo (Brazzaville)	7.1	4.6	2.2	0.2	0.1	4	36.4
Côte d'Ivoire	1.7				1.7	60	24.7
Egypt (Arab Rep.)	45.2	1.1	0.4	1.2	42.5	1 502	42.9
Equatorial Guinea	3.8	1.0	1.2	0.3	1.3	46	26.1
Gabon	2.1	0.3	1.6	0.1	0.1	4	16.7

Table 5-3 Natural gas: 2005 production

	Gross	Re-injected	Flared	Shrinkage	Net	Net	R/P ratio
	(billion cubic metres)					(billion cubic feet)	
Libya/GSPLAJ	19.7	6.5	0.9	1.0	11.3	399	> 100
Morocco	0.1				0.1	2	20.0
Mozambique	0.2				0.2	7	> 100
Nigeria	54.3	7.0	22.9	2.0	22.4	791	> 100
Senegal	0.1				0.1	2	> 100
South Africa	2.9	0.8	0.2		1.9	67	4.8
Tanzania	0.4		N	N	0.4	15	60.0
Tunisia	3.2		0.3	0.3	2.6	92	28.8
Total Africa	**343.3**	**110.1**	**40.7**	**19.6**	**172.9**	**6 107**	**59.2**
Barbados	N				N	1	7.0
Canada	219.1	12.7	1.9	28.3	176.2	6 223	7.9
Cuba	0.6		0.1	0.1	0.4	14	> 100
Mexico	49.8	6.4	2.0	2.2	39.2	1 385	9.5
Trinidad & Tobago	33.2	1.0	0.9	0.7	30.6	1 081	16.5
United States of America	645.0	105.0	3.4	24.8	511.8	18 074	10.9
Total North America	**947.7**	**125.1**	**8.3**	**56.1**	**758.2**	**26 778**	**10.4**
Argentina	51.6	1.3	0.7	4.0	45.6	1 611	8.7
Bolivia	14.7	1.9	0.2	0.2	12.4	436	57.8
Brazil	17.7	3.0	2.5	1.0	11.2	396	20.8
Chile	2.3	0.1	0.1	0.1	2.0	72	44.5
Colombia	15.1	7.4	0.5	0.5	6.7	236	18.2
Ecuador	1.3	0.2	0.8		0.3	9	9.1
Peru	5.6	3.8	0.1	0.2	1.5	54	> 100
Venezuela	61.6	28.4	5.1	4.5	23.6	833	> 100
Total South America	**169.9**	**46.1**	**10.0**	**10.5**	**103.3**	**3 647**	**51.6**
Afghanistan	N				N	1	> 100
Azerbaijan	10.5	0.3	4.1	0.4	5.7	201	> 100
Bangladesh	14.0				14.0	494	31.1
Brunei	13.4	1.6		0.3	11.5	406	28.8
China	48.0				48.0	1 695	49.0
Georgia	N				N	1	> 100
India	32.1		0.9	0.8	30.4	1 075	34.3
Indonesia	89.0	6.5	4.2	4.5	73.8	2 606	33.4
Japan	2.7				2.7	95	18.9
Kazakhstan	25.2		1.2	0.3	23.7	836	> 100
Kyrgyzstan	N				N	1	> 100
Malaysia	69.8			6.3	63.5	2 243	35.5

Table 5-3 Natural gas: 2005 production

	Gross	Re-injected	Flared	Shrinkage	Net	Net	R/P ratio
		(billion cubic metres)				(billion cubic feet)	
Myanmar (Burma)	13.8		0.2	0.6	13.0	459	35.1
Pakistan	34.4	0.6		3.0	30.8	1 088	23.9
Philippines	3.6		0.2	0.5	2.9	102	27.8
Taiwan, China	0.5	N			0.5	19	> 100
Tajikistan	N				N	1	> 100
Thailand	26.2			2.5	23.7	836	11.6
Turkey	1.1		0.2		0.9	32	13.6
Turkmenistan	63.0				63.0	2 225	45.4
Uzbekistan	59.7			0.3	59.4	2 097	31.0
Vietnam	4.8		0.3	0.5	4.0	141	76.0
Total Asia	**511.8**	**9.0**	**11.3**	**20.0**	**471.5**	**16 654**	**41.3**
Albania	N	N			N	1	66.7
Austria	1.6				1.6	58	9.4
Belarus	0.3				0.3	9	10.0
Bulgaria	0.5				0.5	19	2.0
Croatia	2.3				2.3	81	11.7
Czech Republic	0.1				0.1	4	40.0
Denmark	12.1	1.4	0.2		10.5	371	7.7
France	1.8	N		0.7	1.1	38	5.6
Germany	17.4			0.8	16.6	585	10.2
Greece	0.1			0.1	N	1	10.0
Hungary	3.4	0.1		0.1	3.2	113	20.3
Ireland	1.2				1.2	42	8.3
Italy	11.7				11.7	413	14.5
Netherlands	77.5			4.4	73.1	2 582	16.2
Norway	130.8	39.7	0.6	3.5	87.0	3 072	25.9
Poland	5.7			1.2	4.5	159	13.2
Romania	12.6	N		0.2	12.4	438	9.6
Russian Federation	669.0		15.0	13.4	640.6	22 623	71.5
Serbia	0.3			0.1	0.2	8	> 100
Slovakia	0.2				0.2	7	75.0
Slovenia	N				N	N	
Spain	0.2				0.2	6	15.9
Ukraine	20.5	N	N		20.5	724	38.4
United Kingdom	93.3	1.3	1.8	4.5	85.7	3 026	5.2
Total Europe	**1 062.6**	**42.5**	**17.6**	**29.0**	**973.5**	**34 380**	**52.5**
Bahrain	13.3	2.6			10.7	378	8.6
Iran (Islamic Rep.)	152.9	32.6	15.2	7.2	97.9	3 457	> 100

Table 5-3 Natural gas: 2005 production

	Gross	Re-injected	Flared	Shrinkage	Net	Net	R/P ratio
	(billion cubic metres)					(billion cubic feet)	
Iraq	11.4	0.8	7.9	0.2	2.5	87	> 100
Israel	0.7		N		0.7	26	48.6
Jordan	0.3				0.3	9	50.0
Kuwait	15.5		1.0	1.8	12.7	449	> 100
Oman	26.7	6.5	0.8	2.7	16.7	591	41.0
Qatar	57.6	2.0	3.9	5.9	45.8	1 617	> 100
Saudi Arabia	81.4	0.2	0.2	9.8	71.2	2 516	84.3
Syria (Arab Rep.)	8.4	1.5	0.3	0.5	6.1	215	43.2
United Arab Emirates	68.2	15.6	0.9	4.7	47.0	1 659	> 100
Yemen	20.6	20.2		0.4	0.0	0	> 100
Total Middle East	**457.0**	**82.0**	**30.2**	**33.2**	**311.6**	**11 004**	**> 100**
Australia	44.1			5.2	38.9	1 374	17.1
New Zealand	4.2	0.1	N	0.2	3.9	139	7.3
Papua New Guinea	0.1	N			0.1	4	> 100
Total Oceania	**48.4**	**0.1**	**N**	**5.4**	**42.9**	**1 517**	**25.1**
TOTAL WORLD	**3 540.7**	**414.9**	**118.1**	**173.8**	**2 833.9**	**100 087**	**56.5**

Notes:

1. Sources: WEC Member Committees, 2006/7; Cedigaz; national sources

Table 5-4 Natural gas: 2005 consumption

	billion cubic metres	billion cubic feet
Algeria	22.7	803
Angola	0.8	26
Congo (Brazzaville)	0.1	4
Côte d'Ivoire	1.5	53
Egypt (Arab Rep.)	34.2	1 208
Equatorial Guinea	1.3	46
Gabon	0.1	4
Libya/GSPLAJ	5.8	206
Morocco	0.1	2
Mozambique	0.2	7
Nigeria	10.4	366

Table 5-4 Natural gas: 2005 consumption

	billion cubic metres	billion cubic feet
Senegal	0.1	2
South Africa	2.2	78
Tanzania	N	N
Tunisia	3.6	127
Total Africa	**83.1**	**2 932**
Barbados	N	1
Canada	91.4	3 227
Cuba	0.4	14
Dominican Republic	0.3	9
Mexico	50.5	1 784
Puerto Rico	0.7	24
Trinidad & Tobago	14.3	505
United States of America	619.0	21 861
Total North America	**776.6**	**27 425**
Argentina	39.6	1 398
Bolivia	2.1	75
Brazil	19.6	692
Chile	8.5	302
Colombia	6.7	236
Ecuador	0.3	9
Peru	1.5	54
Uruguay	0.1	3
Venezuela	28.7	1 014
Total South America	**107.1**	**3 783**
Afghanistan	N	1
Armenia	1.7	60
Azerbaijan	9.4	334
Bangladesh	14.0	494
Brunei	2.4	83
China	48.0	1 695
Georgia	1.4	49
Hong Kong, China	2.2	78
India	35.9	1 269
Indonesia	37.5	1 325
Japan	79.0	2 791
Kazakhstan	19.1	673
Korea (Republic)	30.5	1 077
Kyrgyzstan	0.7	25
Malaysia	33.2	1 172
Myanmar (Burma)	4.1	146

Table 5-4 Natural gas: 2005 consumption

	billion cubic metres	billion cubic feet
Pakistan	30.8	1 088
Philippines	2.9	102
Singapore	6.6	233
Taiwan, China	10.4	368
Tajikistan	0.6	21
Thailand	31.7	1 120
Turkey	26.4	932
Turkmenistan	17.8	629
Uzbekistan	47.2	1 667
Vietnam	4.0	141
Total Asia	**497.5**	**17 573**
Albania	N	1
Austria	9.6	339
Belarus	20.3	717
Belgium	17.6	621
Bosnia-Herzogovina	0.4	14
Bulgaria	3.1	111
Croatia	2.9	103
Czech Republic	9.3	330
Denmark	4.7	166
Estonia	1.0	34
Finland	4.2	148
FYR Macedonia	0.1	4
France	46.1	1 628
Germany	100.4	3 546
Greece	2.9	102
Hungary	11.4	403
Ireland	4.2	147
Italy	77.9	2 753
Latvia	2.3	81
Lithuania	3.1	109
Luxembourg	1.4	49
Moldova	1.5	53
Netherlands	39.5	1 395
Norway	5.6	197
Poland	15.4	545
Portugal	4.2	148
Romania	17.6	622
Russian Federation	401.0	14 161
Serbia	2.6	91
Slovakia	6.3	223

Table 5-4 Natural gas: 2005 consumption

	billion cubic metres	billion cubic feet
Slovenia	1.1	40
Spain	33.6	1 187
Sweden	1.0	36
Switzerland	3.2	114
Ukraine	76.4	2 698
United Kingdom	99.6	3 517
Total Europe	**1 031.5**	**36 433**
Bahrain	10.7	378
Iran (Islamic Rep.)	103.0	3 637
Iraq	2.5	87
Israel	0.7	26
Jordan	1.6	55
Kuwait	12.7	449
Oman	6.1	216
Qatar	16.8	595
Saudi Arabia	71.2	2 516
Syria (Arab Rep.)	6.1	215
United Arab Emirates	41.3	1 457
Total Middle East	**272.7**	**9 631**
Australia	24.1	849
New Zealand	3.9	139
Papua New Guinea	0.1	4
Total Oceania	**28.1**	**992**
TOTAL WORLD	**2 796.6**	**98 769**

Notes:

1. Sources: WEC Member Committees, 2006/7; Cedigaz; other international and national sources; estimates by the Editors
2. Russian Federation consumption excludes pipeline use

COUNTRY NOTES

The following Country Notes on Natural Gas provide a brief account of countries with significant gas resources. They have been compiled by the Editors, drawing upon a wide variety of material, including information received from WEC Member Committees, national and international publications.

The principal published sources consulted were:

- *Annual Statistical Bulletin 2005*; 2006; OPEC;
- *BP Statistical Review of World Energy, 2006*;
- Cedigaz data;
- *Energy Balances of OECD Countries 2003-2004*; 2006; International Energy Agency;
- *Energy Balances of Non-OECD Countries 2003-2004*; 2006; International Energy Agency;
- *Energy Statistics of OECD Countries 2003-2004*; 2006; International Energy Agency;
- *Energy Statistics of Non-OECD Countries 2003-2004*; 2006; International Energy Agency;
- *Oil & Gas Journal*, 19 December 2006, PennWell Publishing Co.
- *Quarterly Statistics, Fourth Quarter 2006;* 2007; International Energy Agency;
- *Secretary-General's 32nd Annual Report, A.H. 1425-1426/A.D. 2005*; 2006, OAPEC
- *World Oil*, September 2006, Gulf Publishing Company

Brief salient data are shown for each country, including the year of first commercial production of natural gas (where it can be ascertained).

Reserves/Production (R/P) ratios have been calculated on the basis of gross production less quantities re-injected.

Algeria

Proved recoverable reserves (bcm)	4 504
Production (net bcm, 2005)	87.3
R/P ratio (years)	42.8
Year of first commercial production	1961

For the purposes of the present *Survey*, the Algerian WEC Member Committee has reported a proved amount in place of 6 080 bcm, of which 4 504 bcm is classified as proved recoverable reserves. Gas reserves non-associated with crude oil account for 80% of proved recoverable reserves. An additional amount in place of 2 000 bcm, of which 960 bcm is deemed to be recoverable, has also been reported by the Algerian Member Committee.

Net production of natural gas in 2005 was the fifth highest in the world, after Russia, the USA, Canada and Iran. About 45% of gross production was re-injected, while much smaller proportions were flared or abstracted as NGLs. About 74% of net production was exported: 39% of gas exports were in the form of LNG, consigned to France, Spain, Turkey, Belgium, the USA, Italy, Greece, the UK and Japan. Exports by pipeline in 2005 went to Italy, Spain, Portugal, Tunisia and Slovenia. Apart from oil and gas industry use, the main internal markets for Algerian gas are power stations, industrial fuel/feedstock and households.

Argentina

Proved recoverable reserves (bcm)	439
Production (net bcm, 2005)	45.6
R/P ratio (years)	8.7

Information published by the Secretaría de Energía with respect to Argentina's oil and gas reserves situation at end-2005 shows proved reserves of natural gas as 439 bcm, a 19% decrease from the end-2004 level of 542 bcm. The same source states that 'probable reserves', not yet proven but considered to be eventually recoverable, now stand at 249 bcm.

Gas extraction takes place in five sedimentary basins. The greatest production corresponds to the Neuquina Basin which provides 57% of the total, followed by the Austral Basin with 20%, the Northwest Basin with 14% and the Golfo San Jorge with 9%; the contribution of the Cuyana Basin is minimal. About 2.5% of current gross production is re-injected. Marketed production (after relatively small amounts are deducted through flaring and shrinkage) is the highest in South America.

For many years, gas supplies have been augmented by imports from Bolivia, but this flow ceased in October 1999, as the focus of Bolivia's gas exports shifted to Brazil. In a further re-orientation of the South American gas supply structure, Argentina has become a significant exporter in its own right, with a number of pipelines supplying Chile and others to Uruguay and Brazil.

Consumption of indigenous and imported gas in 2004 was divided between the power generation market (33%), industrial fuel/feedstock (23%), residential/commercial uses (23%) and gas industry own use/loss (14%); about 7% was consumed as CNG in road transport.

Australia

Proved recoverable reserves (bcm)	755
Production (net bcm, 2005)	38.9
R/P ratio (years)	17.1
Year of first commercial production	1969

The level of proved recoverable reserves quoted above corresponds to 'Remaining commercial reserves at 1 January 2005' as given in *Oil and Gas Resources of Australia 2004*, published by Geoscience Australia in 2006. Doubtless due to the adoption of differing definitions of 'proved reserves', other published sources tend to quote substantially higher levels for reserves at end-2005, ranging (in terms of bcm) from *Oil & Gas Journal*'s 783 to *World Oil*'s 3 384.

Estimated additional reserves recoverable of 3 314 bcm correspond with ‘Non-commercial reserves’ of sales gas in the Geoscience Australia publication cited above, which also provides an alternative assessment, using the McKelvey classification, resulting in ‘Economic Demonstrated Resources’ of 2 587 bcm and ‘Subeconomic Demonstrated Resources’ of 1 482 bcm, giving a grand total of 4 069.

Australia's principal gas reserves are located in the Carnarvon, Gippsland, Browse, Bonaparte and Cooper Basins.

Gross production grew by over 60% between 1990 and 1996, reflecting in part higher domestic demand but more especially a substantial increase in exports of LNG (almost all to Japan) from the North West Shelf fields. Production growth has continued in recent years, but at a slower pace.

The main gas-consuming sectors in Australia are public electricity generation, the non-ferrous metals industry and the residential sector.

Azerbaijan

Proved recoverable reserves (bcm)	1 350
Production (net bcm, 2005)	5.7
R/P ratio (years)	>100

Azerbaijan is one of the world's oldest producers of natural gas. After years of falling production the outlook has been transformed by recent developments. Proved reserves of gas, as quoted by Cedigaz, have edged down from 1 370 to 1 350 bcm. *Oil & Gas Journal* and OAPEC opt for a lower level (circa 850 bcm). Marketed production in 2005 was 5.7 bcm, of which much the greater part came from offshore fields. About 42% of current gross production is reported to be flared or vented.

Bangladesh

Proved recoverable reserves (bcm)	436
Production (net bcm, 2005)	14.0
R/P ratio (years)	31.1
Year of first commercial production	1961

Whilst the published volumes of proved gas reserves are not particularly large, much of Bangladesh is poorly explored and the potential for further discoveries is thought to be substantial. For the present *Survey*, the Cedigaz assessment of 436 bcm for proved recoverable reserves has been adopted in preference to *Oil & Gas Journal*’s reduced level of 142 bcm.

Gas production has followed a rising trend for many years and has reached 14 bcm per annum. Natural gas contributes nearly three-quarters of Bangladesh's commercial energy supplies; its principal outlets are power stations and fertiliser plants. Consumption by the residential/commercial sector is growing rapidly.

Bolivia

Proved recoverable reserves (bcm)	740
Production (net bcm, 2005)	12.4
R/P ratio (years)	57.8
Year of first commercial production	1955

The level adopted for proved reserves at end-2005 reflects the view of Cedigaz: other published sources broadly concur. Assessments of gas reserves as at 1 January 2005, issued by the state hydrocarbons company YPFB and published by the Instituto Nacional de Estadística, show proved reserves as 27 tcf (765 bcm) and probable reserves as 22 tcf (623 bcm).

Exports to Argentina used to be the major outlet for Bolivia's natural gas, but the focus of Bolivia's gas export trade shifted towards Brazil following the inauguration of two major export lines, one from Santa Cruz de la Sierra to south-east Brazil in 1999 and another in 2000 from San Miguel to Cuiaba. Exports in 2005 amounted to 10.2 bcm.

Internal consumption of gas is still on a small scale (only about 2 bcm/yr), and confined almost entirely to electricity generation and industrial fuel markets, residential use being minimal at present.

Brazil

Proved recoverable reserves (bcm)	306
Production (net bcm, 2005)	11.2
R/P ratio (years)	20.8
Year of first commercial production	1954

Brazil's natural gas industry is relatively small at present compared with its oil sector. Proved reserves, as reported by the Brazilian WEC Member Committee, amount to 306 bcm and are the fifth largest in South America, having increased by 29% over the past 3 years. The level of reserves reported corresponds with the category 'measured/indicated/inventoried' in the *Balanço Energético Nacional (BEN) 2006*, published by the Ministério de Minas e Energia. Of the latest assessment of proved recoverable reserves, approximately 25% is non-associated with crude oil. Additional recoverable reserves, not classified as proved, (corresponding with 'inferred/estimated' resources in the BEN) are put at just over 148 bcm.

Nearly one-third of current gross production of natural gas is either re-injected or flared. Marketed production is mostly used as industrial fuel or as feedstock for the production of petrochemicals and fertilisers. As a consequence of Brazil's huge hydroelectric resources, use of natural gas as a power station fuel had been minimal until fairly recently. The consumption picture is now changing as imported gas (from Bolivia and Argentina) fuels the increasing number of gas-fired power plants that are being built in Brazil. The use of CNG by road vehicles is now a significant feature of the gas market.

Brunei

Proved recoverable reserves (bcm)	340
Production (net bcm, 2005)	11.5
R/P ratio (years)	28.8

Natural gas was found in association with oil at Seria and other fields in Brunei. For many years this resource was virtually unexploited, but in the

1960s a realisation of the resource potential, coupled with the availability of new technology for producing and transporting liquefied natural gas, enabled a major gas export scheme to be devised. Since 1972 Brunei has been exporting LNG to Japan, and more recently to the Korean Republic. Occasional spot sales have been made to other destinations.

Despite annual exports approaching 10 bcm, Brunei's proved reserves as published by *Oil & Gas Journal* have remained virtually steady at just under 400 bcm since 1992. For the purpose of the present *Survey*, the somewhat lower level of 340 bcm quoted by Cedigaz, *World Oil* and BP has been adopted.

Nearly 80% of Brunei's marketed production is exported, the balance being mostly used in the liquefaction plant, local power stations and offshore oil and gas installations. Small quantities are used for residential purposes in Seria and Kuala Belait.

Canada

Proved recoverable reserves (bcm)	1 633
Production (net bcm, 2005)	176.2
R/P ratio (years)	7.9

Canada's gas reserves are the third largest in the Western Hemisphere. The proved recoverable reserves correspond with 'remaining established reserves' of marketable natural gas at 31 December, 2005, as assessed by the Canadian Association of Petroleum Producers (CAPP) in its *2006 Statistical Handbook*.

The recoverable established reserves are estimated to be 1 633 bcm. Western Canada is estimated to have an additional 2 700 bcm of natural gas. The provinces with the largest gas resources are Alberta (with 71% of remaining established reserves), British Columbia (21%) and Saskatchewan (6%).

The East Coast Offshore has about 15 bcm of proven reserves, with a potential for a further 500 bcm.

As with crude oil, the National Energy Board (NEB) undertook probabilistic estimates for the Mackenzie-Beaufort region, and it estimates that there could be 255 bcm of marketable natural gas at the mean probability. Additional resources in excess of 3 000 bcm could exist in Canada's north. At this time the Mackenzie Valley gas pipeline project, which would carry approximately 35 million m^3/d to southern markets, is in the regulatory hearing phase.

Coal-bed methane has recently received a great deal of interest; production from Alberta was almost 2 million m^3/d in 2004. Estimates of the recoverable resource are notoriously difficult to obtain. Figures of up to 7 000 bcm have been published, although there is no consensus.

Gross production of Canadian natural gas is the third highest in the world. Marketed gas output in 2005 was 176 bcm. Over 50% was exported to the United States. The largest users of gas within Canada are the industrial, residential and commercial sectors. A relatively small proportion is consumed in electricity generation.

China

Proved recoverable reserves (bcm)	2 350
Production (net bcm, 2005)	48.0
R/P ratio (years)	49.0
Year of first commercial production	1955

Past gas discoveries have been fewer than those of crude oil, which is reflected in the fairly moderate level of proved reserves. Gas reservoirs have been identified in many parts of China, including in particular the Sichuan Basin in the central region, the Tarim Basin in the north-west and the Yinggehai (South China Sea). China's gas resource base is thought to be enormous: estimates by the Research Institute of Petroleum Exploration and Development, quoted by Cedigaz, put total resources at some 38 000 bcm, of which 21% is located offshore. Most of the onshore gas-bearing basins are in the central and western parts of China.

The level of proved reserves adopted for the present *Survey* has been derived from published sources. Compared with the situation obtaining when the 2004 SER was being compiled, a growing consensus is evident in respect of China’s gas reserves. OPEC and BP quote 2 350 bcm, which is also the level given by Cedigaz for 1 January 2005 – its 1 January 2006 level is presently under review; OAPEC has 2 229, while although *Oil & Gas Journal* gave 1 510 for reserves at 31 December 2005, it raised its estimate to 2 265 for end-2006. The only remaining outlier is *World Oil*’s figure of 1 575 bcm. For present purposes, a level of 2 350 bcm has been adopted.

The major outlets for natural gas within China are as industrial fuel/feedstock (46%), oil/gas industry own use/loss (21%) and the residential/commercial sector (24%). Natural gas has relatively small shares in the generation of electricity and bulk heat. In January 1996, China began delivering natural gas to the Castle Peak power station in Hong Kong via a pipeline from the offshore Yacheng field; deliveries in 2005 were about 2.2 bcm.

Colombia

Proved recoverable reserves (bcm)	140
Production (net bcm, 2005)	6.7
R/P ratio (years)	18.2

The early gas discoveries were made in the north-west of the country and in the Middle and Upper Magdalena Basins; in more recent times, major gas finds have been made in the Llanos Basin to the east of the Andes. Proved reserves at end-2005 are quoted by the Unidad de Planeación Minero Energético (UPME) of the Ministerio de Minas y Energía, in its *Boletín Estadístico 1999-2005* as 3 994 bcf, plus 937 bcf for own use in the gas fields, giving a total of 4 932 bcf (139.7 bcm). This level compares with a fairly wide range of alternative estimates, extending from BP’s 110 to *World Oil’s* 190, with Cedigaz and *Oil & Gas Journal* close to the lower end at around 113 bcm.

At present a high proportion of Colombia's gas output (49% in 2005) is re-injected in order to maintain or enhance reservoir pressures. The major outlets for natural gas are own use by the gas industry (31% of total gas consumption in 2004), chemicals, cement and other industrial users (27%) and power plants (25%). Residential/commercial consumers accounted for 14%, while CNG use in road transport is small but growing rapidly.

Denmark

Proved recoverable reserves (bcm)	82
Production (net bcm, 2005)	10.5
R/P ratio (years)	7.7
Year of first commercial production	1984

The Danish WEC Member Committee quotes the Danish Energy Authority (DEA), which does not use the terms proved and additional reserves, but employs the categories ‘ongoing’, ‘approved’, ‘planned’ and ‘possible recovery’. The DEA expresses natural gas volumes in *normal cubic metres* (Nm^3), measured at 0^oC and 1 013 mb. For the purposes of the present *Survey*, all such data have been converted to *standard cubic metres*, measured at 15^oC and 1 013 mb.

The figure for proved recoverable reserves (82 bcm) has been derived from the sum of ‘ongoing’ and ‘approved’ reserves (78 billion Nm^3), while the figure for additional reserves recoverable (45 bcm) has been derived from the sum of 14 billion Nm^3 ‘planned’ and 29 billion Nm^3 ‘possible’ reserves. Of the reported proved recoverable reserves, 44% is non-associated with crude oil. The Danish Member Committee also reports the amount of gas in place corresponding to the proved recoverable reserves as 564 bcm and that corresponding to the additional reserves recoverable as 53 bcm.

Egypt (Arab Republic)

Proved recoverable reserves (bcm)	1 894
Production (net bcm, 2005)	42.5
R/P ratio (years)	42.9
Year of first commercial production	1964

Proved reserves are the third largest in Africa, having risen 14% since the 2004 *Survey*, according to the latest data reported by the Egyptian WEC Member Committee. There is general agreement amongst the standard published sources on a level of around 1 894 bcm, with the exception of *Oil & Gas Journal*, which quotes 1 657 (unchanged at end-2006). Since the end of 2000, Egypt's gas reserves have exceeded those of its neighbour Libya. About 92% of its reported reserves are non-associated with crude oil.

The major producing area is the Mediterranean Sea region (mostly from offshore fields), although output of associated gas from a number of fields in the Western Desert and the Red Sea region is also important.

Marketed production has grown steadily in recent years and is now the second largest in

Africa. The main outlets at present are power stations, fertiliser plants and industrial users such as the iron and steel sector and cement works.

Germany

Proved recoverable reserves (bcm)	178
Production (net bcm, 2005)	16.6
R/P ratio (years)	10.2

Although it is one of Europe's oldest gas producers, Germany's remaining proved reserves are sizeable, and (apart from the Netherlands) they still rank as the largest onshore reserves in Western Europe. The principal producing area is in north Germany, between the rivers Weser and Elbe; westward from the Weser to the Netherlands border lies the other main producing zone, with more mature fields.

The proved recoverable reserves advised by the German WEC Member Committee draw upon a report issued by the Landesamt für Bergbau, Energie und Geologie, Hannover in 2006 and are some 45% lower than the corresponding level reported for the 2004 *Survey.* While Cedigaz, *World Oil* and BP all quote similar levels to that reported to the WEC, *Oil & Gas Journal* and OPEC show about 255 bcm, which may include the additional 64 bcm of ‘probable reserves’ reported by the Member Committee to be eventually recoverable.

Indigenous production provides only about 20% of Germany's gas supplies; the greater part of demand is met by imports from the Russian Federation, the Netherlands, Norway, the UK and Denmark.

India

Proved recoverable reserves (bcm)	1 101
Production (net bcm, 2005)	30.4
R/P ratio (years)	34.3
Year of first commercial production	1961

A sizeable natural gas industry has been developed on the basis of the offshore Mumbai gas and oil/gas fields. Proved reserves at 1 April, 2005 have been reported by the Indian WEC Member Committee as 1 101 bcm, an increase of 46.6% on the level advised for the 2004 *Survey*. The revised figure appears to be consistent with the series of 'proved and indicated balance recoverable reserves' published by the Ministry of Petroleum & Natural Gas, which shows 1 075 bcm for such reserves at 1 April 2006.

Strong growth in India’s offshore reserves raised them from 584 bcm (63% of total reserves) at 1 April 2004 to 761 bcm (69%) at 1 April 2005.

The Indian WEC Member Committee also reports that the proved amount of gas in place (of which the proved reserves constitute the recoverable portion) is 1 595 bcm.

Marketed production is principally used as feedstock for fertiliser and petrochemical manufacture, for electricity generation and as industrial fuel. The recorded use in the residential and agricultural sectors is very small.

Indonesia

Proved recoverable reserves (bcm)	2 754
Production (net bcm, 2005)	73.8
R/P ratio (years)	33.4

The Indonesian WEC Member Committee reports proved recoverable gas reserves as 97.26 tscf (2 754 bcm), 26% higher than those advised for the 2004 *Survey of Energy Resources*. There has been a noticeable convergence in other published assessments of Indonesia's proved reserves, which at the time of preparation of the 2004 SER varied widely, broadly ranging from 2 100 to 3 800 bcm. End-2005 assessments are all close to the level reported for the present *Survey*.

Indonesia's gas production is the highest in Asia. The main producing areas are in northern Sumatra, Java and eastern Kalimantan.

Exports of LNG from Arun (Sumatra) and Bontang (Kalimantan) to Japan began in 1977-1978. Indonesia has for many years been the world's leading exporter of LNG. Shipments in 2005 were chiefly to Japan (60%) but also to the Republic of Korea (24%) and Taiwan, China (16%). Indonesia exports about half of its marketed production, including (from early 2001) supplies by pipeline to Singapore (4.8 bcm in 2005).

The principal domestic consumers of natural gas (apart from the oil and gas industry) are power stations and fertiliser plants: the residential and commercial sectors have relatively small shares.

Iran (Islamic Republic)

Proved recoverable reserves (bcm)	26 740
Production (net bcm, 2005)	97.9
R/P ratio (years)	> 100
Year of first commercial production	1955

Iran's proved reserves are second only to those of the Russian Federation, (although now closely approached by those of Qatar). They account for 15% of the world total, and exceed the combined proved reserves of North America, South America and Europe (excluding the Russian Federation). The Iranian WEC Member Committee reports that at the end of 2005 proved reserves of natural gas were 26 740 bcm, marginally higher (+0.6%) than the end-2002 level reported for the 2004 *Survey of Energy Resources*.

For many years only minute quantities of associated gas output were utilised as fuel in the oil fields or at Abadan refinery: by far the greater part was flared. Utilisation of gas in the industrial, residential and commercial sectors began in 1962 after the construction of a pipeline from Gach Saran to Shiraz.

In 2005, 64% of Iran's gross production of 153 bcm of gas was marketed; about 21% was re-injected into formations in order to maintain or enhance pressure; about 10% was flared or vented and 5% lost through shrinkage and other factors. The marketed production volume of about 98 bcm was augmented by 5.8 bcm of gas imported from Turkmenistan, whilst 4.3 bcm was exported to Turkey. Iran's principal gas-consuming sectors are electricity generation (39% of total consumption in 2004), residential users (32%) and industry (19%).

Iraq

Proved recoverable reserves (bcm)	3 170
Production (net bcm, 2005)	2.5
R/P ratio (years)	>100
Year of first commercial production	1955

Gas resources are not particularly large, by Middle East standards: proved reserves (as reported by OAPEC) account for less than 5% of the regional total. Most other published sources quote the same figure, the one exception being *World Oil*, with proved reserves given as 2 379 bcm.

According to data reported by Cedigaz, 70% of Iraq's proved reserves consist of associated gas, whilst cap gas and non-associated gas account for 15% each. A high proportion of gas output is thus associated with oil production: some of the associated gas is flared.

Between 1986 and 1990 Iraq exported gas to Kuwait. Currently all gas usage is internal, as fuel for electricity generation, as a feedstock and fuel for the production of fertilisers and petrochemicals, and as a fuel in oil and gas industry operations.

Kazakhstan

Proved recoverable reserves (bcm)	3 000
Production (net bcm, 2005)	23.7
R/P ratio (years)	>100

Kazakhstan has substantial resources of natural gas and may well become a major player on the world stage. The chief discovery so far has been the giant Karachaganak field, located in the north of Kazakhstan, near the border with the Russian Federation. Another major field is Tengiz, close to the north-east coast of the Caspian Sea.

The level of proved reserves adopted for the present *Survey* is based upon the figure quoted by the Government of Kazakhstan as 'approved extracting stocks', which could be construed as equivalent to proved recoverable reserves. Lower levels are given by published compilations of reserves data: Cedigaz 1 900 bcm, OAPEC and OGJ 1 841 bcm (although OGJ has raised its assessment to 2 832 bcm as at 1 January 2007).

Kuwait

Proved recoverable reserves (bcm)	1 586
Production (net bcm, 2005)	12.7
R/P ratio (years)	>100
Year of first commercial production	1960

Note: Kuwait data include its share of Neutral Zone.

Gas reserves (as quoted by OAPEC and other published sources) are relatively low in regional terms and represent only about 2% of the Middle East total. All of Kuwait's natural gas production has been associated with crude oil, so that its availability has been basically dependent on the level of oil output. However, official announcements during 2006 of two major discoveries of non-associated gas have changed the picture. In March it was announced that almost 35 tcf (circa 1 000 bcm) of gas had been discovered in the 'southern north' part of Kuwait; this was followed in June by news of an extractable amount of almost 5 tcf (ca. 140 bcm) in the west of the country. These discoveries are not yet reflected in reserves assessments but, if validated, will have a significant impact in due course.

After allowing for a limited amount of flaring and for shrinkage due to the extraction of NGLs, Kuwait's gas consumption is currently about 13 bcm/yr, one-third of which is used for electricity generation and desalination of seawater.

Libya/GSPLAJ

Proved recoverable reserves (bcm)	1 491
Production (net bcm, 2005)	11.3
R/P ratio (years)	> 100
Year of first commercial production	1970

Proved reserves - the fourth largest in Africa - have been largely unchanged since 1991, according to OAPEC and other published sources. Utilisation of the resource is on a comparatively small scale: net production in 2005 was only about a quarter that of Egypt.

Since 1970 Libya has operated a liquefaction plant at Marsa el Brega, but LNG exports (in recent years, only to Spain) have fallen away to only 0.9 bcm/yr.

Local consumption of gas is largely attributable to petrochemical/fertiliser plants and oil and gas industry use.

Malaysia

Proved recoverable reserves (bcm)	2 480
Production (net bcm, 2005)	63.5
R/P ratio (years)	35.5
Year of first commercial production	1983

Exploration of Malaysia's offshore waters has located numerous fields yielding natural gas or gas/condensates, mainly in the areas east of the peninsula and north of the Sarawak coast. Proved reserves (as quoted by Cedigaz) now stand at 2 480 bcm and rank as the fourth highest in Asia. Other published reserve assessments range from *World Oil's* 1 642 via *Oil & Gas Journal* at 2 124 to OPEC and BP at 2 480 bcm.

Malaysia became a major gas producer in 1983, when it commenced exporting LNG to Japan. This trade has continued ever since, supplemented in recent years by LNG sales to the Republic of Korea and Taiwan, China and by gas supplies via pipeline to Singapore. In 2005, spot sales of LNG were made to Spain and the USA.

Domestic consumption of gas has become significant in recent years, the major market being power generation. The other principal outlet for natural gas, apart from own use within the oil/gas industry, is as feedstock/fuel for industrial users. Small amounts of CNG are used in transport, reflecting an official programme to promote its use.

Mexico

Proved recoverable reserves (bcm)	412
Production (net bcm, 2005)	39.2
R/P ratio (years)	9.5

The Mexican WEC Member Committee reports that proved recoverable reserves at end-2005 were 14 557 bcf (412 bcm), reflecting the level of ‘remaining proved reserves of dry natural gas’ stated by Petróleos Mexicanos (Pemex) in their *Informe Estadístico de Labores 2005*. Within the total amount of proved reserves, 43% are located in the southern region, 30% in the northern region, 17% in the marine north-east region and 10% in the marine south-west region. Pemex also provides estimates of two further resource categories: ‘probable reserves’ of 15 246 bcf (432 bcm) and ‘possible reserves’ of 16 912 bcf (479 bcm).

Production of natural gas has been on a slowly declining trend in recent years. The greater part of Mexico's gas production (66.5% in 2005) is associated with crude oil output, mostly in the southern producing areas, both onshore and offshore.

The Mexican WEC Member Committee reports that Pemex is carrying out a major exploration programme for natural gas. This has been spurred by the large increase in natural gas utilisation for electricity generation in the last decade. At present, one regasification plant (0.5 bcf/d) is operating in the Gulf of Mexico importing LNG, and another is being built on the Pacific coast near the US border.

The largest outlet for gas is as power station fuel (45% of total inland disposals in 2004); industrial fuel/feedstock 30%; the energy industry consumed about 23%, and households about 2%. Mexico habitually exports relatively small amounts of gas to the USA and imports somewhat larger quantities.

Myanmar

Proved recoverable reserves (bcm)	485
Production (net bcm, 2005)	13.0
R/P ratio (years)	35.1

Myanmar has long been a small-scale producer of natural gas, as of crude oil, but its resource base would support a substantially higher output of gas. There appear to be widely differing views on the level of proved reserves: for the purpose of the present *Survey*, the level of 485 bcm published by Cedigaz has been utilised; *World Oil*’s figure equates to 358 bcm and that in *Oil & Gas Journal* to only 283.

Until 2000, gas production tended to oscillate around a slowly rising trend. With the commencement of exports of natural gas to Thailand from two offshore fields, first Yadana and subsequently Yetagun, Myanmar's gas industry has entered a new phase. As offtake by Thailand's 3 200 MW Ratchaburi Power Plant has built up, gas production in Myanmar has moved onto a significantly higher level than in the past. Domestic consumption of gas is mainly for power generation.

Netherlands

Proved recoverable reserves (bcm)	1 256
Production (net bcm, 2005)	73.1
R/P ratio (years)	16.2

The Netherlands WEC Member Committee, quoting advice from the Netherlands Institute of Applied Geoscience TNO, reports proved recoverable reserves as 1 256 bcm, somewhat below the range of end-2005 volumes given by the standard published sources (1 387-1 756 bcm). However, Dutch reserves still represent one of the largest gas resources in Western Europe. The giant Groningen field in the north-west of the Netherlands accounts for almost two-thirds of the country's proved reserves.

The estimated additional amount in place is given by the Member Committee as ranging from 180 to 440 bcm, but no indications of the volume recoverable were available to report.

Gas production has tended to fluctuate in recent years, depending on weather conditions in Europe, thus demonstrating the flexibility that enables the Netherlands to play the role of a swing producer.

Over half of Netherlands gas output is exported, principally to Germany but also to Italy, Belgium, France, the UK and Switzerland. The principal domestic markets are electricity and heat generation, the residential sector and industrial fuel and feedstock.

New Zealand

Proved recoverable reserves (bcm)	30
Production (net bcm, 2005)	3.9
R/P ratio (years)	7.3
Year of first commercial production	1970

The Maui offshore gas/condensate field (discovered in 1969) is the largest hydrocarbon deposit so far discovered in New Zealand: it presently accounts for 46% of the country's economically recoverable gas reserves. Effective utilisation of its gas resources has been a key factor in New Zealand's energy policy since the early 1980s.

The proved recoverable reserves reported by the New Zealand WEC Member Committee for the present *Survey* correspond with estimates of ‘proven and probable reserves’ (or P50 values) compiled by the Ministry of Economic Development, on the basis of information provided by field operators. These reserves have been assessed within the context of ‘ultimate recoverable reserves’ of about 159 bcm. The Member Committee also reports an estimated additional amount in place of 1 144 bcf (approximately 31 bcm), based on reserves in non-producing fields for which Petroleum

Mining Permits have been granted. All fields have been appraised and all final investment decisions concerning development have been made. Five fields (Kupe, Pohokura, Tui, Maari and Turangi) are scheduled to come into production during 2006-2008.

The latest assessment of proved reserves is substantially lower than that for end-2002 (42 bcm), largely due to a major reduction in Maui's reserves. The Maui field came into commercial production in 1979 when a pipeline to the mainland was completed. Three plants were commissioned in the 1980s to use indigenous gas, producing (respectively) methanol, ammonia/urea and synthetic gasoline. Ten gas fields were in production in 2005, with Maui accounting for 57% of total output.

An extensive transmission and distribution network serves industrial, commercial and residential consumers in the North Island. Small (and declining) amounts of CNG are used in motor vehicles.

Nigeria

Proved recoverable reserves (bcm)	5 150
Production (net bcm, 2005)	22.4
R/P ratio (years)	>100
Year of first commercial production	1963

In contrast to the situation reported on in the 2004 *Survey*, published assessments of Nigeria's proved reserves of natural gas at the end of 2005 all fall within a narrow band (5 150 to 5 230 bcm). The level adopted for the present *Survey* is that quoted by Cedigaz and closely matched by OPEC (5 152), *World Oil* (5 154) and OAPEC/BP/*Oil & Gas Journal* at around 5 230 (note that OGJ quotes 5 151 for gas reserves as at 1 January 2007).

Nigeria's proved reserves on this basis are now the largest in Africa, ahead of those of Algeria, but historically its degree of gas utilisation has been very low. Much of the associated gas produced has had to be flared, in the absence of sufficient market outlets. Efforts are being made to develop gas markets, both locally and internationally, and to reduce flaring to a minimum. There are projects to replace non-associated gas by associated gas in supplies to power stations and industrial users. About 42% of Nigeria's gross gas production of 54.3 bcm in 2005 was flared or vented.

The Bonny LNG plant (commissioned in the second half of 1999) exported 12 bcm of natural gas as LNG during 2005, chiefly to Spain and France, with smaller quantities going to Portugal, Turkey and the USA. A project is under way for the construction of a pipeline to supply Nigerian associated gas to power plants in Benin, Togo and Ghana.

Norway

Proved recoverable reserves (bcm)	2 358
Production (net bcm, 2005)	87.0
R/P ratio (years)	25.9
Year of first commercial production	1977

Resource data have been obtained primarily from the Norwegian Petroleum Directorate (NPD). Proved reserves are the highest in Europe (excluding the Russian Federation). The bulk of reserves is located in the North Sea, the rest having been discovered in the Norwegian Sea and the Barents Sea. The level of proved recoverable reserves reported by the NPD amounted to 2 358 bcm at end-2005; similar levels are quoted by *Oil & Gas Journal, World Oil* and BP. On the other hand, Cedigaz, OAPEC and OPEC give higher figures, which appear to include the NPD's 'contingent resources' and 'potential from improved recovery'. At end-2005, contingent resources in fields were put at 156 bcm, those in discoveries at 494 bcm and potential from improved recovery at 100 bcm. In addition, NPD estimated that the recoverable potential of undiscovered gas was 1 900 bcm.

In the NPD's terminology, 'reserves' cover 'remaining recoverable, saleable petroleum resources in petroleum deposits that the licensees have decided to develop, and for which the authorities have approved the PDO[3] or granted a PDO exemption'. 'Contingent resources' are defined as 'discovered quantities of petroleum for which no development decision has yet been made'. 'Undiscovered resources' are 'petroleum volumes which are expected to be present in defined exploration models, confirmed and unconfirmed, but which have not yet been proven through drilling'.

[3] PDO = Plan for Development and Operation

Norway's gas production continues to follow a rising trend. A high proportion (30% in 2005) of output is re-injected; nearly 94% of marketed production is exported. In 2005 supplies went to 12 European countries, principally Germany, France, Belgium, Italy, the UK and the Netherlands. Apart from gas industry own use, Norway's internal consumption of gas is still at a very low level, being largely confined to minor feedstock use.

Oman

Proved recoverable reserves (bcm)	829
Production (net bcm, 2005)	16.7
R/P ratio (years)	41.0
Year of first commercial production	1978

Oman is one of the smaller gas producers in the Middle East, with moderate proved reserves which have fallen slightly since 2002, on the basis of OAPEC data. The levels of reserves quoted in other published sources are fairly widely dispersed, ranging from *World Oil*'s 766 bcm to BP's 1 000, with OAPEC and *Oil & Gas Journal* at 829 and Cedigaz and OPEC towards the top end at 995. For the sake of consistency with previous editions, the present *Survey* uses the level published by OAPEC.

Oman has developed its utilisation of gas to such an extent that oil has long been displaced as the Sultanate's leading energy supplier. Currently, the principal outlet for marketed gas is the power generation/desalination complex at

Ghubrah. Other gas consumers include mining and cement companies.

The Oman LNG project began operating in early 2000, with the first shipment (to the Republic of Korea) taking place in April. Regular shipments of LNG are also being made to Japan, whilst during 2005 additional supplies (including spot cargoes) were delivered to Spain, France, the USA, India and Taiwan, China.

Pakistan

Proved recoverable reserves (bcm)	807
Production (net bcm, 2005)	30.8
R/P ratio (years)	23.9
Year of first commercial production	1955

The levels of natural gas resources and reserves quoted in the present *Survey* have been derived from the *Pakistan Energy Yearbook 2006*, published by the Hydrocarbon Development Institute of Pakistan, Ministry of Petroleum and Natural Resources. Proved recoverable reserves have been taken as equivalent to 28.5 tcf of 'Balance Recoverable Reserves' at 30 June 2006, expressed in normalised tcf at 900 Btu/cf. The *Yearbook* shows this figure as being derived from 'Original Recoverable Reserves' of 49.0 tcf (1 388 bcm) by subtracting cumulative production of 20.5 tcf (581 bcm). The resulting level is marginally higher than that reported for end-2002 by the WEC Member Committee (28 288 bcf, equivalent to 801 bcm). It is perhaps illustrative of the uncertainties of resource assessment that only two of the standard published sources consulted in the course of the present *Survey* are agreed upon a level for Pakistan's gas reserves (Cedigaz and *World Oil*: 852 bcm).

Currently, the major gas-producing fields are Sui in Balochistan and Qadirpur and Mari in Sindh. Only 4% of natural gas output is associated with oil production.

Production of natural gas increased by 60% over the 5 years to 2005-06. The major markets for gas (excluding own use) in that year were power generation (40%), industrial users (24%), fertiliser plants (16%) and households and commercial consumers (16%). Rapidly growing quantities of CNG are consumed as a transport fuel.

Papua New Guinea

Proved recoverable reserves (bcm)	428
Production (net bcm, 2005)	0.1
R/P ratio (years)	> 100
Year of first commercial production	1991

The Hides gas field was discovered in 1987 and brought into production in December 1991. Other resources of non-associated gas have been located in PNG, both on land and offshore. Published assessments of proved reserves range between *Oil & Gas Journal*'s 345 bcm and the 430 quoted by BP, with *World Oil* positioned midway at 388 bcm. For the present *Survey*, the (unchanged) level of 428 bcm given by Cedigaz and OPEC has been retained.

Up to the present, the only marketing outlet for Hides gas has been a 42 MW gas-turbine power plant serving the Porgera gold mine; offtake averages 14-15 million cubic feet/day. Associated gas produced in the Kutubu area is mostly re-injected into the formation.

The PNG Gas Project for a gas export pipeline to Australia is progressing slowly. The proposed pipeline includes a 500 km undersea section across the Torres Strait and 2 100 km of line following a route southwards close to the coastline of Queensland. ExxonMobil, which has a 26% working interest, reported in its 2006 *Financial and Operating Review* that it was advancing the project. The Australian pipeline consortium had withdrawn from the scheme following the completion of front-end engineering and design. ExxonMobil also reported that 'multiple development options', including an LNG project, were being explored.

Peru

Proved recoverable reserves (bcm)	338
Production (net bcm, 2005)	1.5
R/P ratio (years)	>100

In terms of natural gas reserves, Peru is placed in the middle rank of South American countries, alongside Argentina, Bolivia and Brazil. The Peruvian WEC Member Committee reports proved recoverable reserves as 11 927 660 million cubic feet (337.7 bcm) at end-2005. Some published sources (Cedigaz, BP) concur, but OGJ and *World Oil* specify a lower figure (247 bcm) which probably reflects the end-2003 level.

The WEC Member Committee also reports that 97.4% of Peru's 'proved reserves' are non-associated and that reserves recoverable, in addition to the proved amount, are some 193 bcm – this reflects the level of 'probable reserves' published by the Ministerio de Energía y Minas, which also quotes 'possible reserves' of 11 612 bcf (329 bcm) in its *Anuario Estadístico de Hidrocarburos 2005*.

Gas output used to be mostly associated with oil production, but the coming on-stream of Pluspetrol's non-associated gas production in the Selva Sur has radically altered the situation, such that less than 17% of gross production in 2005 was associated with oil production. An appreciable proportion of production (68% in 2005) is re-injected. Flaring and shrinkage are reported to be on a small scale.

Marketed production of gas averaged about 0.4 bcm/yr from around 1990 until 2003 but rose sharply in 2004 and 2005, with Pluspetrol's new output. Electricity generation accounts for about 80% of Peru's gas consumption.

Qatar

Proved recoverable reserves (bcm)	25 633
Production (net bcm, 2005)	45.8
R/P ratio (years)	>100
Year of first commercial production	1963

Qatar's gas resources far outweigh its oil endowment: its proved reserves of gas of almost 26 trillion m^3 are only exceeded within the Middle East by those reported by Iran, and account for nearly 15% of global gas reserves. The WEC Member Committee for Qatar reports that remaining proved recoverable reserves (here defined as ‘proven ultimate recovery minus cumulative production’) were 905.24 tcf (25 633 bcm) at end-2005. Published sources are all closely in line with this level.

Although associated gas has been discovered in oil fields both on land and offshore, the key factor in Qatar's gas situation is non-associated gas, particularly that in the offshore North Field, one of the largest gas reservoirs in the world. The WEC Member Committee reports that non-associated gas accounts for almost 99% of Qatar’s gas reserves.

Production of North Field gas began in 1991 and by 2005 Qatar's total annual gross production had risen to about 58 bcm; 3.5% was re-injected and around 10% lost through shrinkage. The gas consumed locally is principally for power generation/desalination, fertiliser and petrochemical production and gas industry own use.

Since the end of 1996, Qatar has become a substantial exporter of LNG; in 2005, shipments exceeded 27 bcm of gas, of which 31% was consigned to Japan, 31% to the Republic of Korea, 21% to India, 17% to Spain and a small amount to the USA.

Romania

Proved recoverable reserves (bcm)	121
Production (net bcm, 2005)	12.4
R/P ratio (years)	9.6

The Romanian WEC Member Committee reports proved recoverable reserves of 120.9 bcm, a further reduction on the 163.3 bcm reported for the 2004 *Survey* and the 405.6 bcm advised for the 2001 edition. Published assessments of Romania’s gas reserves vary widely, ranging from *Oil & Gas Journal*’s 101 bcm (reduced to only 63 at end-2006) to Cedigaz and BP at around 630 bcm. The proportion of proved recoverable reserves that is non-associated with crude oil is reported to be 90.4%.

The reported additional amount of 'unproved' gas in place has fallen again, from 100.6 to 70.7 bcm, of which approximately 32% is considered to be recoverable.

After peaking in the mid-1980s, Romania's natural gas output has been in gradual secular decline, falling to around 12 bcm in recent years, only about one-third of its peak level. Indigenous production currently supplies about two-thirds of Romania's gas demand; the principal users are power stations, CHP and district heating plants, the steel and chemical industries and the residential/commercial sector.

Russian Federation

Proved recoverable reserves (bcm)	47 820
Production (net bcm, 2005)	640.6
R/P ratio (years)	71.5

The gas resource base is by far the largest in the world: Russia's proved reserves are quoted as 47 820 bcm by Cedigaz. Other major published sources quote figures very similar to this level.

However, there is some evidence to suggest that the generally quoted quantification of Russia's gas reserves may overstate their magnitude in relation to the proved recoverable reserves reported for certain other countries. While the Russian WEC Member Committee was unable to provide a figure for proved recoverable reserves, it has reported the 'proved amount in place' as 8 425.61 bcm and the 'estimated additional amount in place' as 39.4 tcm, of which 9.037 tcm is stated to be recoverable. This is not to belittle the extent of Russian gas resources, but simply to advocate caution in drawing precise comparisons with reserve estimates for other parts of the world.

The greater part (77%) of the Federation's reserves are located in West Siberia, where the existence of many giant, and a number of super-giant, gas fields has been proved.

The Federation's net natural gas production of 640.6 bcm in 2005 accounted for almost 23% of the world total.

Russia is easily the largest exporter of natural gas in the world: in 2005, according to Cedigaz, its exports reached just over 240 bcm, of which about 145 bcm went to European countries and the balance to former republics of the Soviet Union.

Saudi Arabia

Proved recoverable reserves (bcm)	6 848
Production (net bcm, 2005)	71.2
R/P ratio (years)	84.3
Year of first commercial production	1961

Note: Saudi Arabia data include its share of Neutral Zone.

Most of Saudi Arabia's proved reserves and production of natural gas are in the form of associated gas derived from oil fields, although a number of sources of non-associated gas have been discovered. In total, proved reserves of gas (6 848 bcm, according to OAPEC) rank as the third largest in the Middle East. Other published sources quote essentially the same level.

Output of natural gas has advanced fairly steadily for more than twenty years. A significant factor in increasing the utilisation of Saudi Arabia's gas resources has been the operation of the gas-processing plants set up under the Master Gas System, which was inaugurated in the mid-1980s. These plants produce large quantities of ethane and LPG, which are used within the country as petrochemical feedstock; a high proportion of LPGs is exported. The main consumers of dry natural gas (apart from the gas industry itself) are power stations, desalination plants and petrochemical complexes.

Thailand

Proved recoverable reserves (bcm)	304
Production (net bcm, 2005)	23.7
R/P ratio (years)	11.6
Year of first commercial production	1981

Thailand's WEC Member Committee reports proved recoverable reserves at end-2005 as 10 743 bcf (equivalent to 304.2 bcm), implying a 31% reduction on the level advised for the 2004 SER. Other published assessments of Thailand's proved gas reserves are all higher than the level reported for the *Survey*, but cover a wide range, from Cedigaz at 305 bcm, to *World Oil* at 648, with BP (350) and *Oil & Gas Journal* (418) in between.

Since its inception 20 years ago, Thailand's natural gas output has grown almost unremittingly year after year. Much the greater part of Thailand's gas output is used for electricity generation; industrial use for fuel or chemical feedstock is relatively small, whilst transport use (CNG) is increasing rapidly.

Thailand began to import natural gas from Myanmar in 1999; in 2005 the volume involved was 8.9 bcm.

Trinidad & Tobago

Proved recoverable reserves (bcm)	532
Production (net bcm, 2005)	30.6
R/P ratio (years)	16.5

Trinidad's WEC Member Committee reports proved reserves of natural gas as 18.78 tcf (531.8 bcm). Most published sources quote very similar levels, the only exception being *Oil & Gas Journal*, which gave the equivalent of 733 bcm for end-2005, although subsequently it has quoted 532 for end-2006.

Marketed production of gas has increased rapidly during recent years, as exports from the Atlantic LNG plant (inaugurated in 1999) have built up. Local consumption is also on the increase, reflecting a government policy of promoting the utilisation of indigenous gas through the establishment of major gas-based industries: fertilisers, methanol, urea and steel. In 2004 the chemical and petrochemical industries accounted for about 63% of Trinidad's gas consumption, power stations for 20% and other industry (including iron and steel) for 9%; the balance of consumption is accounted for by use/loss within the gas supply industry.

Turkmenistan

Proved recoverable reserves (bcm)	2 860
Production (net bcm, 2005)	63.0
R/P ratio (years)	45.4

Apart from the Russian Federation, Turkmenistan has the largest proved reserves of any of the former Soviet republics: for the present *Survey*, the level of 2 860 bcm quoted by Cedigaz has been adopted, in preference to the lower figure (2 010 bcm) given by *Oil & Gas Journal* and OAPEC. (It may be noted that OGJ has subsequently raised its figure to 2 832 bcm as at end-2006).

Cedigaz has stated that Turkmenistan's total gas resources have been evaluated at 22.9 trillion cubic metres. Many gas fields have been discovered in the west of the republic, near the Caspian Sea, but the most significant resources have been located in the Amu-Darya Basin, in the east.

Gas deposits were first discovered in 1951 and by 1980 production had reached 70 bcm/yr. It continued to rise throughout the 1980s, but by 1992 a serious contraction of the republic's export markets had set in and output fell sharply. Natural gas output recovered in 1999, and has since advanced to 63 bcm in 2005. Exports to countries outside the CIS amounted to 8.6 bcm in 2005, of which Iran accounted for 5.8 bcm.

Ukraine

Proved recoverable reserves (bcm)	787
Production (net bcm, 2005)	20.5
R/P ratio (years)	38.4

The Ukrainian WEC Member Committee reports that proved recoverable reserves were 787 bcm at end-2005, within a proved amount in place of 1 021 bcm. The available published sources (Cedigaz, *Oil & Gas Journal* and BP) all show proved recoverable reserves between 1 100 and 1 121 bcm, appreciably higher than the latest reported figure. Gas associated with crude oil was stated to account for only about 3% of the proved reserves.

Over and above the proved quantities, the WEC Member Committee estimates that there was about 357 bcm of gas in place, of which around 169 bcm was likely to be recoverable.

Ukraine's output of natural gas has been virtually flat since 1994, although production in 2004-2005 was on a somewhat higher level. The republic is one of the world's largest consumers of natural gas: demand reached 137 bcm in 1990. Although consumption had fallen back to about 76 bcm by 2005, indigenous production met only 27% of local needs; the balance was imported from Russia and Turkmenistan. The principal areas of consumption are households, industry and the generation of electricity and bulk heat.

United Arab Emirates

Proved recoverable reserves (bcm)	6 071
Production (net bcm, 2005)	47.0
R/P ratio (years)	> 100
Year of first commercial production	1967

Four of the seven emirates possess proved reserves of natural gas, with Abu Dhabi accounting for by far the largest share. Dubai, Ras-al-Khaimah and Sharjah are relatively insignificant in regional or global terms. Overall, the UAE accounts for about 8% of Middle East proved gas reserves.

OAPEC's published level of UAE gas reserves (6 071 bcm) is little changed from that quoted in the 2001 and 2004 *Surveys*. Apart from *World*

Oil, which gives a figure of 5 820 bcm, the other main published sources (Cedigaz, *Oil & Gas Journal*, OPEC and BP), all quote UAE reserves within a very narrow band (6 040 - 6 071 bcm).

Two major facilities - a gas liquefaction plant on Das Island (brought on-stream in 1977) and a gas-processing plant at Ruwais (in operation from 1981) - transformed the utilisation of Abu Dhabi's gas resources. Most of the plants' output (LNG and NGLs, respectively) is shipped to Japan. In 2005, other LNG customers comprised Spain and the Republic of Korea.

Within the UAE, gas is used mainly for electricity generation/desalination, and in plants producing aluminium, cement, fertilisers and chemicals.

United Kingdom

Proved recoverable reserves (bcm)	481
Production (net bcm, 2005)	85.7
R/P ratio (years)	5.2
Year of first commercial production	1955

The UK is no longer Europe's leading offshore gas producer, having been overtaken by Norway in 2006. The data on gas resources and reserves adopted for the present *Survey* are based on those reported by the British Energy Association, the UK Member Committee of the WEC, on the basis of advice from the Department of Trade and Industry.

Proved recoverable reserves at end-2005 are reported to be 481 bcm, being the sum of ‘gas from dry gas fields’ (191 bcm), ‘gas from condensate fields’ (186) and ‘associated gas from oil fields’ (104). In this context the DTI defines ‘proven reserves’ as those ‘which on the available evidence are virtually certain to be technically and economically producible, i.e. have a better than 90% chance of being produced’.

'Probable' reserves (with a better than 50% chance of being technically and economically producible) are put at 247 bcm, whilst 'possible' reserves (with a significant, but less than 50%, chance) are estimated as 278 bcm.

It may be noted that Cedigaz quotes UK proved reserves of natural gas as 728 bcm, i.e. the sum of ‘proved’ and ‘probable’ reserves in DTI parlance, whereas most of the other standard published sources report them as 531 bcm, reflecting DTI proved reserves as at end-2004, being the latest available at the time of their compilation.

Potential additional reserves exist in discoveries for which there are no current plans for development and which are currently not technically or commercially producible. The DTI states that, on the basis of information gathered during the first quarter of 2006, these reserves are considered to lie within a range of 68 to 282 bcm, with a central estimate of 141 bcm. In the course of time, as additional data become available and development plans evolve, some of the ‘potential additional reserves’ gas is likely to be transferred to ‘reserves’.

The DTI has also produced estimates of ‘undiscovered recoverable resources’, based for the most part on an analysis of mapped leads.

The latest update has produced a range of undiscovered gas resources from 226 to 1 035 bcm, with a central estimate of 421 bcm. It is pointed out by the DTI that such figures provide only a broad indication of the ultimate remaining potential and that the central estimate is not necessarily the volume most likely to be discovered. The figures quoted do not include any estimates of unconventional gas resources such as coal-bed methane.

It should be noted that all UK gas reserves are reported in terms of *recoverable* quantities: the corresponding volumes of gas *in place* do not form part of the published data on gas resources. Moreover, the recoverable quantities exclude any gas that is flared, as well as gas consumed in production operations.

Natural gas production rose year-by-year during the 1990s, reflecting burgeoning consumption in the power generation sector and higher exports at the end of the decade, following the commissioning of the Interconnector pipeline between Bacton in the UK and Zeebrugge in Belgium, in October 1998. Total output peaked in 2000, since when it has followed a downward trend year-by-year.

United States of America

Proved recoverable reserves (bcm)	5 866
Production (net bcm, 2005)	511.8
R/P ratio (years)	10.9

The USA possesses the world's sixth largest proved reserves of natural gas, and accounts for just over 3% of the global total. Apart from the Russian Federation and the United States, all other countries in the top 10 for gas reserves are members of OPEC.

The figure of 5 866 bcm tabulated above is derived from total proved reserves of dry natural gas at end-2005 (204 385 bcf), as given by the Energy Information Administration in its *U.S. Crude Oil, Natural Gas and Natural Gas Liquids Reserves 2005 Annual Report.* For the purposes of the present *Survey*, the original data in billion cubic feet at 14.73 psia and 60^{o}F have been transformed into standard SER terms (1 013 mb and 15^{o}C) by means of separate adjustments for pressure and temperature.

During the 3 years since the last edition of the *Survey of Energy Resources*, US gas reserves have registered an increase of 17 439 bcf, or about 494 bcm. Total additions to reserves in 2003-2005 were 30.6% greater than the amount of gas produced during the same period.

The 17.4 tcf net increase in reserves during 2003-2005 was due partly to discoveries (field extensions, new field discoveries and new reservoir discoveries in old fields, totalling 62.6 tcf during the three-year period), partly to revisions and adjustments to estimates for old fields (+6.4 tcf) and partly to the net balance of sales and acquisitions (+5.4 tcf). Cumulative production during the three-year period was some 57 tcf.

Total discoveries during 2005 amounted to 23.2 tcf, the largest component comprising field extensions, notably in Texas, Wyoming, Oklahoma, Colorado and Louisiana. The states with the largest gas reserves at end-2005 were Texas (27.6% of the USA total), Wyoming (11.6%), New Mexico (8.9%) and Oklahoma (8.4%). Reserves in the Federal Offshore areas in the Gulf of Mexico accounted for 8.3% of the total. About 87% of proved reserves consist of non-associated gas.

Uzbekistan

Proved recoverable reserves (bcm)	1 850
Production (net bcm, 2005)	59.4
R/P ratio (years)	31.0

The republic's first major gas discovery (the Gazlinskoye field) was made in 1956 in the Amu-Darya Basin in western Uzbekistan. Subsequently, other large fields were found in the same area, as well as smaller deposits in the Fergana Valley in the east.

For the present *Survey*, the level of 1 850 bcm quoted by Cedigaz has been adopted for proved recoverable reserves.

Uzbekistan is a major producer of natural gas: its 2005 net output was, for example, greater than that of Egypt or Qatar. It exports gas to some of its neighbouring republics.

The principal internal markets for natural gas are the residential/commercial sector, power stations, CHP and district heating plants, and fuel/feedstock for industrial users. Some use is made of CNG in road transport.

Venezuela

Proved recoverable reserves (bcm)	4 315
Production (net bcm, 2005)	23.6
R/P ratio (years)	>100

Venezuela has by far the biggest natural gas industry in South America, possessing two-thirds of regional proved reserves and accounting for 23% of its marketed production in 2005.

In the absence of any reserves data released by the Ministerio de Energía y Minas later than 151 479 bcf (4 289 bcm) at end-2004, the level for end-2005 quoted by Cedigaz and OPEC (4 315 bcm) has been adopted for the present *Survey.* Other published sources tell much the same story: *Oil & Gas Journal* and OAPEC 4 287 bcm, *World Oil* 4 273 and BP 4 320.

Substantial quantities of Venezuela's natural gas (amounting to around 46% of gross output in 2005) are re-injected in order to boost or maintain reservoir pressures, while smaller amounts (8%) are vented or flared; about 7% of production volumes are subject to shrinkage as a result of the extraction of NGLs.

The principal outlets for Venezuelan gas are power stations, petrochemical plants and industrial users, notably the iron and steel and cement industries. Residential use is on a relatively small scale.

Yemen

Proved recoverable reserves (bcm)	479
Production (net bcm, 2005)	-
R/P ratio (years)	>100

Yemen has appreciable reserves of natural gas - currently quoted by OAPEC as 479 bcm - but no commercial utilisation has so far been established. Cedigaz, *Oil & Gas Journal, World Oil* and BP all quote the same level of proved reserves, within +/- 2 bcm.

Commercialisation of Yemen's gas will soon become a reality. An LNG plant is under construction at Balhaf, with its start-up scheduled for end-2008. The plant will consist of two trains, and be capable of delivering 6.7 million tonnes/yr of LNG. Natural gas will be supplied from two gas-processing plants in the Marib gas field via a 320 km pipeline.

6. Part I: Uranium

COMMENTARY

Overview

With headlines of licence extensions instead of early retirements of nuclear power plants, and the prospect of dwindling cheap and reliable fossil fuel supplies, burgeoning energy demand and increasing environmental constraints, the world is witnessing a resurgent interest in nuclear power as a clean, abundant and economically competitive electricity supply option. After almost two decades of decline or, at best, stagnation, numerous countries or utilities, until recently oblivious or opposed to the technology, have begun to reassess nuclear power as a secure and economically competitive base-load electricity generating technology.

Populous countries with rapidly developing economies such as China and India pursue aggressive expansion of all electricity generating options, including nuclear power. Russia has announced that it wishes to increase its nuclear generating capacity from the current level of 21.7 GW_e to 44 GW_e by 2020. In the Republic of Korea a nuclear share in the national electricity mix of close to 60% is seen as a desirable medium-term target (up from the current 40%).

After more than 20 years without a single new order, utilities in the United States are positioning themselves for an initial round of plant orders, in part stimulated by government incentives, in part by economic and environmental considerations. Finland and France are building or have decided to build third-generation nuclear power plants. The United Kingdom Energy White Paper of May 2007 keeps open the option of constructing new nuclear power plants in the future. Energy policy in Belarus, Poland and Turkey has moved in favour of building nuclear power stations. The *World Energy Technology Outlook* – 2050 of the European Commission (EC, 2006) projects a significant increase in nuclear power after 2020 worldwide. Such projections are consistent with the growing number of countries expressing an interest in nuclear energy for electricity production. A meeting organised by the International Atomic Energy Agency (IAEA) in December 2006 to examine *Issues for the Introduction of Nuclear Power* was attended by 28 (predominantly developing) countries that currently do not operate nuclear power plants.

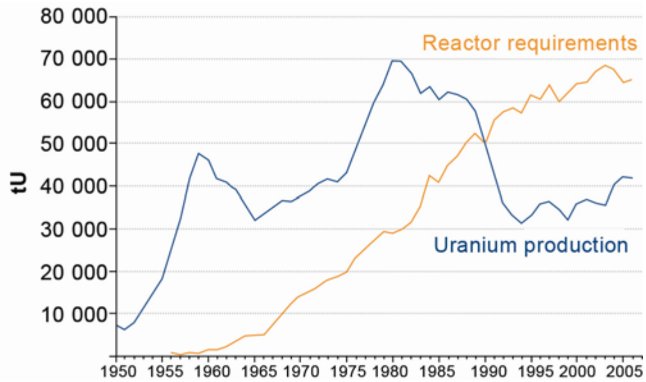
This upbeat outlook on nuclear power is in stark contrast to the not-so-distant past, with years of suppressed growth prospects, including nuclear phase-out policies in several countries, with the consequent impact on uranium exploration activities and production capacities. Nuclear technology and fuel cycle infrastructures are complex and capital-intensive, with long lead times. Without clear long-term demand signals from the market place, the uranium industry has been reluctant to invest in new mine capacities or to pursue large-scale uranium exploration.

In addition to the uncertain outlook for nuclear power, the uranium market has been characterised by a large disparity between global reactor requirements and mine production (Fig. 6-1) since the early 1990s when, after decades of production exceeding requirements by an unusually wide margin, mine output slipped below annual reactor requirements. The appearance of so-called secondary supplies (i.e. reactor fuel derived from warheads, military and commercial inventories, re-enrichment of depleted uranium tails, as well as enriching at lower tail assays, reprocessed uranium and mixed oxide fuel) reduced demand for fresh uranium. In addition, new entrants to the world uranium market, e.g., Kazakhstan, Uzbekistan and the Russian Federation, further exerted competitive pressures. As a result of uncertain and low demand plus excess capacity, uranium prices (except for short-term aberrations) fell.

Usually low prices suggest plentiful supplies. Utilities therefore began to hold lower inventories, which suppressed production and prices even further and overall operational mine capacity dropped below reactor requirements. A fair share of the market apparently turned a blind eye to the fact that requirements were increasingly met by accumulated past production and not from operating capacities. In late 2000, uranium prices reached an historical low of US$ 7.10/lbU_3O_8 or US$ 18.45/kgU, threatening the economic survival of many mines. At the same time, global production had progressively declined to less than 60% of reactor requirements. In short, uranium prices no longer reflected longer-term production capacities.

Shortly after prices hit the historical low, a series of events uncovered the long-ignored

Figure 6-1 Global annual uranium production and reactor requirements[4], 1950-2006[5]
Source: adapted from NEA/IAEA, 2006



demand/supply imbalance and caused prices to rise. Among the triggering factors were a fire in Australia's Olympic Dam mill and the flooding of the world's largest and highest-grade uranium mine, McArthur River in Canada. Both mines were among the top global producers and the drop in output resulted in market prices rising immediately. On the demand side, since 1990 rising plant factors of the world's nuclear fleet added incrementally to annual reactor fuel requirements the equivalent of more than 30 GW_e. A series of licence renewals for existing reactors that began around the turn of the century sent plant operators out to secure fuel for another 20 years or so. Another change was the growth of nuclear power in the developing economies of China and India, countries that had either not participated in the market to a great extent or had not participated at all. While demand was picking up momentum, supply from mine output continued to be underprovided.

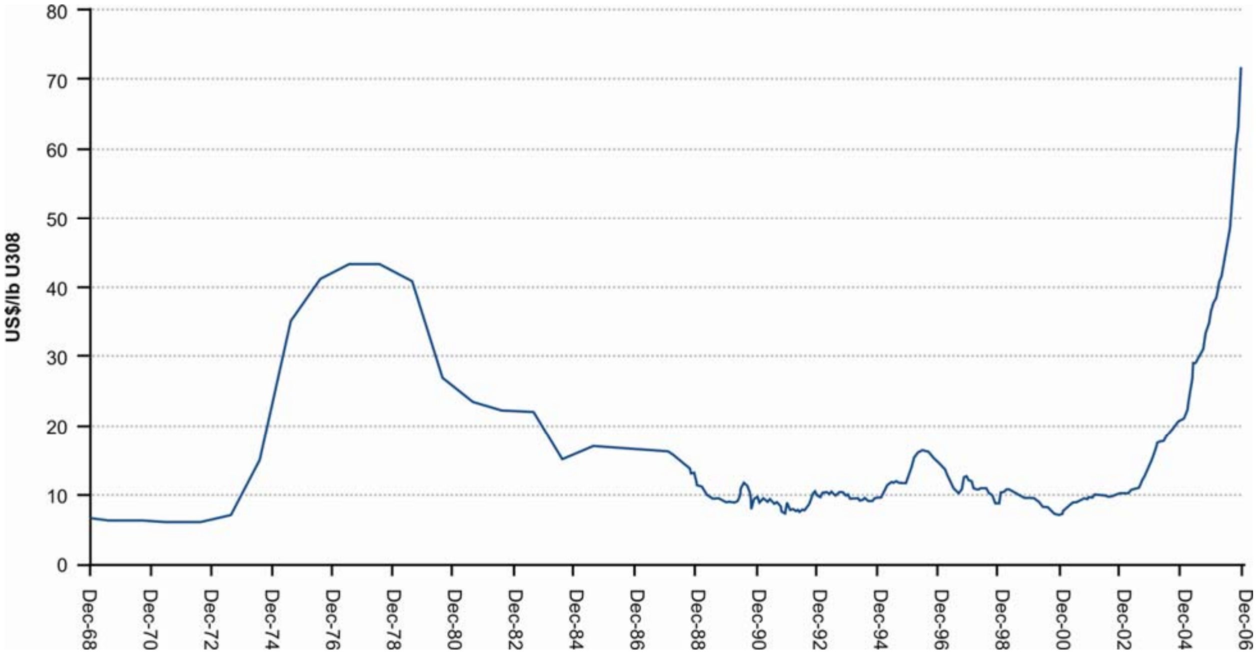
Concerns surfaced with regard to the global industry's ability to meet a potential surge in demand for uranium and with short-run supplies from mines capped and rising demand expectations, uranium prices began to climb (Fig. 6-2). Higher prices were seen by most market participants as a necessary prerequisite to correct past market anomalies and to stimulate investment in direly-needed new production capacity (Combs, 2006). Despite some uncertainty on the precise future availability of fissile materials from military arsenals that still exists, it became clear that the bulk of future uranium supply must come from mine output, i.e., investment in exploration and development of new mines and mills. In the short run, however, because there is no ready-to-produce project on the shelf, the production cannot increase rapidly despite rising demand. As a result, in six years the uranium spot price has been multiplied by a factor of ten.

The market reacted as expected and mine re-opening and the expansion of existing facilities increased global mine production capacity from about 45 000 tU in 2001 to more than 52 000 tU in 2006 – still well below current annual reactor requirements. Numerous new mine openings are planned or under preparation, but given the long lead times of up to ten years and more between an investment decision and first mine output, the markets will have to continue to rely on secondary sources for another decade or so. One important source, the agreement to downblend highly enriched uranium (HEU) from the Russian weapons programme, will however be stopped after 2013, when the agreement expires.

Planned new mine capacities, especially in Australia, Canada and Kazakhstan, are considered essential for re-aligning uranium production and reactor requirements for the post-2015 period. Prices and demand prospects are now at levels that warrant additional investments in exploration and production. However, the market remains tight – the 2006 rockfall and water inflow at the Cigar Lake mine

[4] Resources and production quantities are expressed in terms of tonnes (t) of contained uranium (U) rather than in terms of uranium oxide (U_3O_8).
[5] Data for 2006 estimated

Figure 6-2 Development of uranium spot market prices*, 1968–2006
Source: adapted from NEA/IAEA, 2006



*Note: Long-term contract prices may differ significantly from spot-market prices and are currently much lower than the spot price, of say US$ 91/lb U_3O_8, but indicate the tightness of the market in the short run.

in Canada, which will delay the opening of the mine, with an estimated annual output of close to 7 000 tU, by one to two years, sent uranium spot-market prices to US$ 75/lbU_3O_8 or US$ 194.80/kgU in February 2007[6].

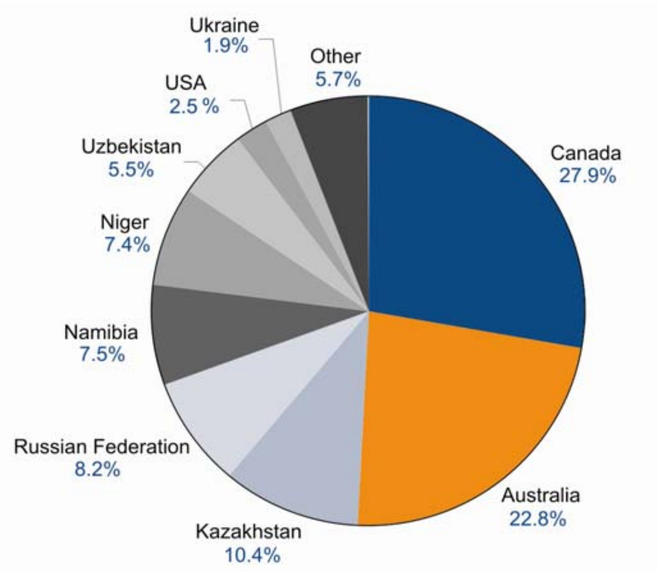
Another development since 2004 has been the emergence of investment funds in the uranium market – in part prompted by the lasting demand and production imbalance and a view that secondary sources eventually need to be replaced by primary production. These funds hold uranium entirely for speculative reasons, confident in the knowledge that prices will continue to increase and that uranium will sell at a profit. Although the volumes involved are a small portion of the total market, investment funds helped raise spot prices in 2005 and 2006.

Soaring spot-market prices and the wide gap between uranium production and reactor requirements have questioned the ability of the uranium and nuclear fuel-cycle industry to respond to a nuclear renaissance. Indeed it would be the 'ultimate irony if fuel became the Achilles heel in the nuclear turnaround instead of one of nuclear's greatest advantages' (Melbye, 2006). The issue of long-term uranium supply has especially been at the centre of debates about the role of nuclear power in sustainable energy development. Statements like 'the reserve-to-production ratio of uranium amounts to only some 60 years' (essentially implying to the uninitiated that new-build nuclear power plants, with an anticipated economic life time of 60 years, will run out of nuclear fuel before their date of decommissioning) are not only misleading but irrelevant.

Uranium supply is usually framed within a short-term market perspective that focuses on prices, on who is producing and with what resources, where might spare capacity exist to meet short-term demand peaks and how does this balance with demand? In essence, the skill is in the understanding of supply/demand/price interdependencies and dynamics for known uranium resources. In contrast, long-term supply (given sufficient demand) is a question of the replenishment of known resources with new resources presently unknown or from known deposits presently not producible for techno-economic reasons. Here the development of

[6] Most uranium, however, is bought on long-term contracts, and between 2000 and 2006 medium- and long-term uranium prices only increased by 20–45%.

Figure 6-3 Top ten uranium producers in 2005 total production 41 699 tU [49 173 t U_3O_8]
Source: IAEA



advanced exploration and production technologies is an essential prerequisite for the long-term availability of uranium. Demand prospects and competitive markets are the essential drivers for technology change and investment to ensure sufficient long-term supply, both through the discovery of new resources and the exploitation of known resources that were previously not accessible (Rogner, 2000). There is no doubt that production capacity will catch up with demand again. But the current challenge before the uranium industry is to shift from a mode of merely responding to short-term market changes to a mode of anticipation of the true longer-term uranium demand and supply balances.

Production[7]

Commercially, uranium is presently produced in 19 countries, although less than half produce significant quantities. The nine leading countries, ranked in order of production, are Australia, Canada, Kazakhstan, the Russian Federation, Namibia, Niger, Uzbekistan, the United States and Ukraine. Together these nine countries provided almost 95% of the world's uranium mine output in 2005. The two largest producers, Canada and Australia, alone account for more than 50% of world uranium production (Fig. 6-3).

Prompted by the current and expected uranium market prices, several countries which historically produced uranium but discontinued for economic reasons (e.g., Argentina, Bulgaria, Chile, Finland) have begun to reconsider reopening closed mines or have stepped up exploration activities. Likewise, other countries previously not producing uranium have boosted efforts to explore the possibility of eventually launching uranium mining activities (e.g., Egypt, Indonesia, Iran and Nigeria).

During the period 2004 to 2006 global uranium production fluctuated between 40 260 tU and 41 700 tU, a 15% increase over the 2000 - 2003 production level. Although mine production alone satisfies only 60% of reactor requirements, uranium supply and demand remain in balance as secondary sources have made up the difference from stockpiles of natural and enriched uranium, the reprocessing of spent fuel and the re-enrichment of depleted uranium tails.

Open-pit and underground mining and conventional milling continue to be the dominant uranium production technologies, accounting for

[7] The production data reported in this section are based on the NEA/IAEA Redbook 2005 (NEA/IAEA, 2006) and information from the website of the World Nuclear Association (WNA): http://www.world-nuclear.org/info/inf23.html

30% and 38% respectively of total production in 2005. While the share of open-pit mining has remained fairly constant since 2000, the share of underground mining has declined by 4%. *In-situ* leaching (ISL) has become the technology of choice in Kazakhstan, the Russian Federation, Uzbekistan and Australia (Beverley mine) and the ISL share has increased by 4% to a 21% share in 2005. Uranium is also produced as a co-product or by-product of copper and gold operations. The volumes of by-product uranium depend on the market situations of the respective main products; in 2005 they contributed 11.1% to global fresh uranium supply. Small amounts of uranium are also recovered from water treatment and environmental-restoration activities.

Exploration

Worldwide exploration expenditures in 2004 totaled over US$ 133 million, an increase of almost 40% compared to 2002 expenditure. The implications of the diverging trend of reactor requirements and fresh uranium production were finally recognised and increasing uranium prices provided the previously-lacking economic incentive for accelerated exploration worldwide. Most major producing countries, but also countries without previous production, reported significant increases in exploration expenditure, perhaps best exemplified by the United States, where exploration expenditure in 2002 amounted to well under US$ 1 million but by 2004 had jumped to over US$ 10 million (NEA/IAEA, 2006).

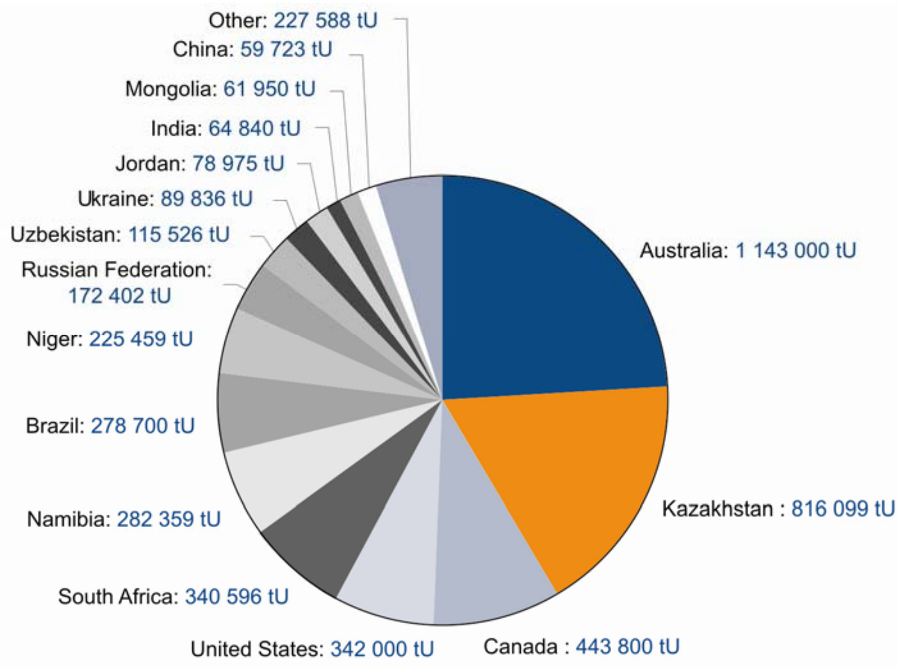
Exploration activities continued to expand through 2005 and 2006 and are expected to reach and possibly exceed US$ 200 million per year. Although data on actual expenditure are not yet available, the number of new exploration companies provides an indication of the dynamics unfolding in the industry: the number exploded from 25 in 2004 to more than 300 entities in 2006 (Jander, 2006). Whilst exploration activities concentrated predominantly on sites close to existing mines/deposits or on potentially promising regions based on past work, the rising price also stimulated grass-roots exploration.

What could be the possible impact of higher exploration activities on the potential discovery of new uranium deposits? Historically, finding uranium incurred average exploration costs of the order of US$ 2/kgU (ranging from US$ 0.25/kgU to almost US$ 11/kgU) for the period 1945 to 2003 (NEA, 2006). These cost data have to be cautiously interpreted, as the easy-to-find deposits have already been discovered and future discoveries are likely to be more costly. Innovation advances in the geosciences and technology, however, continue to keep costs under control.

Resources

Uranium is a metal approximately as common as tin or zinc, and it is a constituent of most rocks and even of the sea (WNA, 2007). The economically-producible occurrences of any mineral are a function of concentration, exploration and production technology, demand

Figure 6-4 Distribution of Identified Resources at US$ 130/kgU
Source: NEA/IAEA, 2006



and market price. Hence resource availability changes dynamically with improved geological knowledge, advances in production technology and increased price expectations. At higher prices, lower-concentration occurrences may become economically attractive, while innovative production methods may enable production from deposits previously beyond reach. Low prices may reduce previously economic resources to easy-to-produce high-concentration sources. This does not mean that the physical occurrence of the mineral no longer exists – it just delineates the economically recoverable portion of that resource at a given point in time (Rogner, 2000). Thus, assessment of the future availability of any mineral, including uranium, which is based (a) on current production costs and price data and (b) on state-of-the-art technology and existing geological knowledge (as most resource assessments do) is erring on the conservative side.

Recent and detailed information on uranium resources is reported in the publication *Uranium 2005: Resources, Production and Demand* (Red Book), a joint report of the OECD Nuclear Energy Agency and the International Atomic Energy Agency (NEA/IAEA, 2006). The resources reported by 44 countries are classified by the level of confidence in the estimates, and by production cost-categories. The 2005 Red Book deviates somewhat from the resource categorisation used in former Red Book editions. Identified Resources[8] consist of two categories (a) Reasonably Assured Resources (RAR) and (b) Inferred Resources[9] (both reported in terms of recoverable uranium for three production cost-ranges, i.e., less than US$ 40/kgU, less than US$ 80/kgU and less than US$ 130/kgU).

Total Reasonably Assured Resources increased by 4% between 2003 and 2005 to 3.297 mtU[10] (Table 6-1) and Inferred Resources by 1.9% over the same period (Table 6-2). Total Identified Resources amounted to 4.743 mtU (an increase of 3.3% over the 2003 resource levels). What is more important is the significant increase in the Identified Resources' lowest cost-category (production costs of less than US$ 40/kgU) of 13% compared to 2003. Given the much lower growth of Total Identified Resources of 3.3% over the period, this increase in the lowest cost-category is not the result of new discoveries but the effect of re-evaluations of

[8] Previously labelled 'Known Conventional Resources'
[9] Previously labelled 'Estimated Additional Resources I (EAR-I)'
[10] Million (metric) tonnes of contained uranium

Figure 6-5 Development of Identified Uranium Resources at less than US$ 130/kg production costs, 1973–2005
Source: NEA/IAEA, 2006

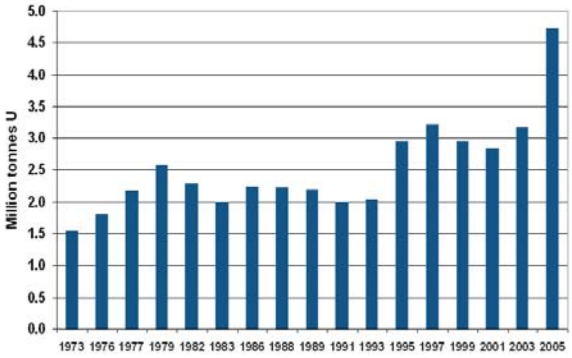


Figure 6-6 Typical uranium concentrations (parts per million U)
Source: World Nuclear Association

High-grade ore (2% U)	20 000
Low-grade ore (0.1% U)	1 000
Granite	4
Sedimentary rock	2
Earth's average continental crust	2.8
Seawater	0.003

already-known resources prompted by the drastically changed market conditions. Given the limited maturity and geographical coverage of uranium exploration worldwide there is considerable potential for the discovery of new resources of economic interest.

Undiscovered Resources (Prognosticated Resources[11] and Speculative Resources) add another estimated 7.1 mtU at costs less than US$ 130/kgU (Table 6-3). This includes both resources that are expected to occur either in or near known deposits, and more speculative resources that are thought to exist in geologically favourable, yet unexplored areas. There are also an estimated further 3.0 mtU of speculative resources for which production costs have not been specified. Given the rather limited economic relevance of these occurrences in the short to medium run, the resource quantities have remained essentially unchanged since 2003.

Resource totals, on balance, increased between 2003 and 2005, indicating that increased uranium prices and demand expectations have triggered a re-evaluation of known resources, especially abandoned deposits where production costs exceeded revenues during the low-price era, and have dramatically accelerated exploration expenditures. Continuing efforts in both areas can be expected to lead to further additions to the identified uranium resource base, just as during past periods of heightened exploration efforts.

[11] Formerly Estimated Additional Resources II (EAR-II)

Unconventional uranium resources and thorium further expand the resource base. Unconventional resources are occurrences that require novel technologies for their exploitation and/or use and often represent low-concentration occurrences. Some typical uranium concentrations are shown in Fig. 6-6.

Unconventional uranium resources include about 22 mtU that occur in phosphate deposits and up to 4 000 mtU contained in sea water. The technology to recover uranium from phosphates is mature, with estimated costs of US$ 60–100/kgU. The technology to extract uranium from sea water has only been demonstrated at the laboratory scale, and extraction costs were estimated in the mid-1990s at US$ 260/kgU (Nobukawa, et al., 1994) but scaling up laboratory-level production to thousands of tonnes is unproven and may encounter unforeseen difficulties.

Thorium is three times as abundant in the Earth's crust as uranium. Although existing estimates of thorium reserves plus additional resources total more than 4.5 mt, such estimates are considered still conservative. They do not cover all regions of the world and the historically weak market demand has limited thorium exploration (IAEA, 2007).

The exploitation of unconventional uranium occurrences would require additional research and development efforts for which there is no imminent economic necessity, given the large conventional resource base and the option of reprocessing and recycling spent fuel. However,

Figure 6-7 Years of uranium availability for nuclear power[12]
Source: IAEA, 2007

Reactor/fuel cycle	Years of 2005 world nuclear electricity generation with identified resources	Years of 2005 world nuclear electricity generation with total conventional resources	Years of 2005 world nuclear electricity generation with total conventional and unconventional resources
Current once-through fuel cycle with light water reactors	85	270	675
Pure fast reactor fuel cycle with recycling	5 000 – 6 000	16 000 – 19 000	40 000 – 47 000

niche opportunities may be explored in greater detail in the not-so-distant future. For example, an international consortium has set out to explore the commercial extraction of uranium from uraniferous coal ash from coal power stations located in Yunnan province, China.

Fig. 6-7 summarises the potential longevity of the world's conventional uranium resources. For both the current light water reactors (LWR) once-through fuel cycle and a pure fast reactor fuel cycle, the estimates demonstrate how long conventional uranium resources would last, assuming electricity generation from nuclear power remains at its 2005 level. Identified uranium resources used in once-through mode with current reactor technology and enrichment practices would last 85 years. Closed fuel-cycles and pure fast breeder reactor technology extend the uranium resource reach to several thousand years.

Exploitation of undiscovered resources would increase these timelines to several hundreds of years (once-through) and tens of thousands of years (closed-fuel cycle and fast breeders), although significant exploration and development would be required to move these resources to more definitive categories.

[12] The values in the last row of Fig. 6.7 assume that fast reactors allow essentially all uranium-238 to be bred to plutonium-239 for fuel, except for minor losses of fissile material during reprocessing and fuel fabrication. The resulting values are higher than estimates published in a similar table in *Uranium 2005: Resources, Production and Demand*. The latter estimates assume that not all uranium-238 is bred to plutonium-239 for fuel.

Supply and Demand Outlook – the next two decades

Each year, the IAEA provides a range of projections on future nuclear electricity generation, reflecting the inherent uncertainties in estimating future developments. In its 2006 projection for 2030, the range of nuclear electricity generation varied between 3 074 TWh and 5 043 TWh (2005: 2 625 TWh). The corresponding reactor fuel requirements would range between 78 000 tU and 129 000 tU by 2030 (IAEA, 2006).

Uranium resources are plentiful and *per se* do not pose a limiting factor to future nuclear power development. As so often, the limiting factor is timely investment in new production capacities. The current reactor requirements and uranium production anomaly calls for significant mine development in order to turn 'uranium in the ground into yellowcake in the can'. Given that the lead times for turning uranium in the ground into yellowcake have become much longer than 30 years ago, global reactor requirements will continue to depend on secondary sources for another decade or so.

Current uranium spot prices exceed the US$ 130/kgU threshold used for delineating identified uranium resources by 50%. This price level not only stimulates additional exploration and mine capacity development around the world but also promotes the intensified use of secondary sources, especially in the longer run. The future role of secondary supplies will depend on economics and policy, especially with regard to spent-fuel reprocessing and high-level waste disposal.

One exception is inventories. While inventories will continue to be held for security reasons, the vast amounts of the past have declined substantially. Current inventories are estimated to be of the order of 34 000 tU (NEA/IAEA, 2006). HEU from weapons programmes is expected to become available for commercial purposes in due course, but the precise quantities and timing remain uncertain.

Secondary Sources. Reprocessing of spent nuclear fuel can contribute to a better uranium demand and supply balance. Annual discharges of spent fuel from the world's reactors total about 10 500 metric tonnes of heavy metal (t HM) per year, approximately one third of which is reprocessed to extract usable material (uranium and plutonium) for new mixed oxide (MOX) fuel. The remaining spent fuel is considered as waste and is stored pending disposal. Currently, China, France, India, Japan, the Russian Federation and the United Kingdom either reprocess, or store for future reprocessing, most of their spent fuel. Most countries have not yet decided which strategy to adopt for dealing with their spent fuel. For the time being they are storing it and keeping abreast of developments associated with reprocessing and direct disposal (IAEA, 2007).

The use of MOX fuel reduces the demand for mined uranium. In MOX the fissile isotope U^{235} is partially replaced by Pu^{239} from reprocessed spent fuel (or surplus weapons plutonium) and mixed with depleted uranium oxide. Recycling of plutonium reduces the natural uranium needs by approximately 15%, as one tonne of MOX fuel requires recycled plutonium from 6 tonnes of spent fuel. In 2006, approximately 180 tonnes of civil origin MOX fuel were loaded on a commercial basis in Belgium, France, Germany and Switzerland, replacing some 2% of freshly mined uranium globally.

Recycling of uranium from reprocessing spent fuel, known as reprocessed uranium (RepU), could further reduce the needs by approximately 10%. RepU is, however, at present generally not recycled for economic reasons, but stored for future use. It currently displaces an estimated 1% of world uranium demand. Changing market conditions could make the use of RepU an economically attractive uranium supply option.

The accumulated stock of depleted uranium tails (the left-over uranium after enrichment) represents a significant secondary source through re-enrichment. Depleted uranium tails usually contain between 0.25% and 0.35% U^{235} compared with the 0.711% U^{235} of natural uranium. By lowering the uranium tails, more enriched uranium can be extracted through re-enrichment. The economic value of re-enrichment, however, is a function of the price of natural uranium, the degree of depletion of the tail assays, the available enrichment capacity and the costs of separate work units (SWU) (Neff, 2006). Total inventories of depleted uranium are estimated to represent the equivalent of 565 000 tU or eight years of fuel requirements for the world's current fleet of nuclear power plants.

As with re-enrichment, demand for fresh uranium is affected by the level of enrichment or the level of tail assays. Lowering tail assays from 0.3% to 0.1% would reduce the demand for mined uranium by about 30%. However, the same factors as in the case of re-enrichment govern the actual levels of tail assays.

Primary Uranium Production. Irrespective of the future contribution of secondary sources, primary uranium production capacity has to increase substantially over the next two decades. Based on current, committed and planned additional mining capacities, the Red Book (NEA/IAEA, 2006) assesses a maximum annual production capacity of some 86 000 tU by 2025 (2006: 52 000 tU). This capacity would just meet the reactor requirements of IAEA's Low nuclear electricity projection but would fall seriously below the High projection of 129 000 tU by 2030. However, the Red Book estimates are based on the US$ 80/kgU resource category. At prices above the US$ 130/kgU production cost category and bright demand prospects, additional investments in new mining capacity can reasonably be expected.

Conclusion

In summary, nuclear fuel resources are plentiful and can meet future demand well into the future. Global primary uranium production capacity must increase substantially over the next two decades to make up for the declining contribution of civilian inventories and military sources and to meet additional demand. In the longer run, secondary sources such as reprocessing, MOX fuel and plutonium use may again supplement primary uranium production, depending on the relative economics of different reactor and fuel-cycle configurations. In either case, a continued strong market and sustained high prices will be necessary for resources to be allocated within the timeframe required to meet future reactor fuel demand.

H-Holger Rogner
International Atomic Energy Agency (IAEA)

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DEFINITIONS

Uranium does not occur in a free metallic state in nature. It is a highly reactive metal that interacts readily with non-metals, and is an element in many intermetallic compounds.

This *Survey* uses the system of ore classification developed by the Nuclear Energy Agency (NEA) of the Organisation for Economic Cooperation and Development (OECD) and the International Atomic Energy Agency (IAEA). Estimates are divided into separate categories according to different levels of confidence in the quantities reported.

The estimates are further separated into categories based on the cost of uranium recovered at ore-processing plants. The cost categories are: less than US$ 40/kgU; US$ 40/kgU to US$ 80/kgU and US$ 80/kgU to US$ 130/kgU. Costs include the direct costs of mining, transporting and processing uranium ore, the associated costs of environmental and waste management, and the general costs associated with running the operation (as defined by the NEA). The resource data quoted in the present *Survey* reflect those published in the 2005 'Red Book'. Cost categories are expressed in terms of the US dollar as at 1 January 2005.

The WEC follows the practice of the NEA/IAEA and defines estimates of discovered reserves in terms of uranium recoverable from mineable ore and not uranium contained in the ore (i.e. to allow for mining and processing losses).

Although some countries continue to report in-situ quantities, the major producers generally conform to these definitions.

All resource estimates are expressed in terms of tonnes of recoverable uranium (U), not uranium oxide (U_3O_8).

Note:

- 1 tonne of uranium = approximately 1.3 short tons of uranium oxide;
- US$ 1 per pound of uranium oxide = US$ 2.60 per kilogram of uranium;
- 1 short ton U_3O_8 = 0.769 tU.

Proved reserves correspond to the NEA category 'Reasonably Assured Resources' (RAR), and refer to recoverable uranium that occurs in known mineral deposits of delineated size, grade and configuration such that the quantities which could be recovered within the given production cost ranges with currently proven mining and processing technology can be specified. Estimates of tonnage and grade are based on specific sample data and measurements of the deposits and on knowledge of deposit characteristics. Proved reserves have a high assurance of existence.

Inferred Resources refers to recoverable uranium (in addition to proved reserves) that is inferred to occur, based on direct geological evidence, in extensions of well-explored deposits and in deposits in which geological continuity has been established, but where specific data and measurements of the deposits and knowledge of their characteristics are considered to be inadequate to classify the resource as a proved reserve.

Undiscovered Resources refers to uranium in addition to proved reserves and inferred resources and covers the two NEA categories, ‘Prognosticated Resources’ (PR) and ‘Speculative Resources’ (SR).

PR refer to deposits for which the evidence is mainly indirect and which are believed to exist in well-defined geological trends or areas of mineralisation with known deposits.

SR refers to uranium that is thought to exist mostly on the basis of indirect evidence and geological extrapolations in deposits discoverable with existing exploration techniques.

Annual production is the production output of uranium ore concentrate from indigenous deposits, expressed as tonnes of uranium.

Cumulative production is the total cumulative production output of uranium ore concentrate from indigenous deposits, expressed as tonnes of uranium, produced in the period from the initiation of production until the end of the year stated.

TABLES

Table 6-1 Uranium: Proved Reserves (RAR) as of 1 January 2005 (thousand tonnes of uranium)
(conventional resources recoverable at up to US$130/kgU)

	Recoverable at				Total recoverable at
	< US$40/kgU	US$40-80/kgU	<US$80/kgU	US$80-130/kgU	up to US$130/kgU
Algeria			19.5		19.5
Central African Republic			6.0	6.0	12.0
Congo (Democratic Rep.)			1.4		1.4
Gabon				4.8	4.8
Malawi			8.8		8.8
Namibia	62.2	89.1	151.3	31.3	182.6
Niger	172.9	7.6	180.5		180.5
Somalia				4.9	4.9
South Africa	88.5	88.6	177.1	78.5	255.6
Zimbabwe			1.3		1.3
Total Africa	**323.6**		**545.9**		**671.4**
Canada	287.2	58.0	345.2		345.2
Greenland				20.3	20.3
Mexico				1.3	1.3
United States of America			102.0	240.0	342.0
Total North America	**287.2**		**447.2**		**708.8**
Argentina	4.8	0.1	4.9	2.2	7.1
Brazil	139.9	17.8	157.7		157.7
Chile					0.6
Peru		1.2	1.2		1.2
Total South America	**144.7**		**163.8**		**166.6**
China	25.8	12.2	38.0		38.0
India					42.6
Indonesia		0.3	0.3	4.3	4.6
Japan				6.6	6.6
Kazakhstan	278.8	99.5	378.3	135.6	513.9
Mongolia	8.0	38.2	46.2		46.2
Thailand				N	N
Turkey		7.4	7.4		7.4
Uzbekistan	59.7		59.7	17.2	76.9
Vietnam					1.0
Total Asia	**372.3**		**529.9**		**737.2**

Table 6-1 Uranium: Proved Reserves (RAR) as of 1 January 2005 (thousand tonnes of uranium)
(conventional resources recoverable at up to US$130/kgU)

	Recoverable at				Total recoverable at
	< US$40/kgU	US$40-80/kgU	<US$80/kgU	US$80-130/kgU	up to US$130/kgU
Bulgaria	1.7	4.2	5.9		5.9
Czech Republic		0.5	0.5		0.5
Finland				1.1	1.1
Germany				3.0	3.0
Greece	1.0		1.0		1.0
Italy			4.8		4.8
Portugal		6.0	6.0	1.0	7.0
Romania				3.1	3.1
Russian Federation	57.5	74.2	131.7		131.7
Slovenia		1.2	1.2		1.2
Spain		2.5	2.5	2.4	4.9
Sweden				4.0	4.0
Ukraine	28.0	30.5	58.5	8.2	66.7
Total Europe	**88.2**		**212.1**		**234.9**
Iran (Islamic Rep.)				0.4	0.4
Jordan	30.4		30.4		30.4
Total Middle East	**30.4**		**30.4**		**30.8**
Australia	701.0	13.0	714.0	33.0	747.0
Total Oceania	**701.0**		**714.0**		**747.0**
TOTAL WORLD	**1 947.4**		**2 643.3**		**3 296.7**

Notes:

1. Data for the intermediate cost-bands are not available for all countries; so regional and global aggregates have not been computed for these categories
2. Source: *Uranium 2005: Resources, Production and Demand*, 2006, OECD Nuclear Energy Agency and International Atomic Energy Agency

Table 6-2 Uranium: Inferred Resources as of 1 January 2005 (thousand tonnes of uranium)
(conventional resources recoverable at up to US$130/kgU)

	Recoverable at				Total recoverable at
	< US$40/kgU	US$40-80/kgU	<US$80/kgU	US$80-130/kgU	up to US$130/kgU
Congo (Democratic Rep.)			1.3		1.3
Gabon				1.0	1.0
Namibia	61.2	25.1	86.3	13.5	99.8
Niger		45.0	45.0		45.0
Somalia				2.5	2.5
South Africa	54.6	17.0	71.6	13.4	85.0
Total Africa	**115.8**		**204.2**		**234.6**
Canada	84.6	14.0	98.6		98.6
Greenland				12.0	12.0
Mexico				0.5	0.5
Total North America	**84.6**		**98.6**		**111.1**
Argentina	2.9		2.9	5.7	8.6
Brazil		73.6	73.6	47.4	121.0
Chile					0.9
Peru			1.3		1.3
Total South America	**2.9**		**77.8**		**131.8**
China	5.9	15.8	21.7		21.7
India					22.3
Indonesia				1.2	1.2
Kazakhstan	129.3	99.1	228.4	73.8	302.2
Mongolia	8.2	7.5	15.7		15.7
Thailand				N	N
Uzbekistan	31.0		31.0	7.6	38.6
Vietnam			0.8	4.6	5.4
Total Asia	**174.4**		**297.6**		**407.1**
Bulgaria	1.6	4.7	6.3		6.3
Czech Republic		0.1	0.1		0.1
France				11.7	11.7
Germany				4.0	4.0
Greece			6.0		6.0
Italy				1.3	1.3
Portugal		1.2	1.2		1.2
Romania				3.6	3.6
Russian Federation	21.6	19.1	40.7		40.7
Slovenia		2.7	2.7	2.8	5.5
Spain				6.4	6.4

Table 6-2 Uranium: Inferred Resources as of 1 January 2005 (thousand tonnes of uranium)
(conventional resources recoverable at up to US$130/kgU)

	Recoverable at				Total recoverable at
	< US$40/kgU	US$40-80/kgU	<US$80/kgU	US$80-130/kgU	up to US$130/kgU
Sweden				6.0	6.0
Ukraine	6.5	10.8	17.3	5.8	23.1
Total Europe	**29.7**		**74.3**		**115.9**
Iran (Islamic Rep.)				1.1	1.1
Jordan	48.6		48.6		48.6
Total Middle East	**48.6**		**48.6**		**49.7**
Australia	343.0	17.0	360.0	36.0	396.0
Total Oceania	**343.0**		**360.0**		**396.0**
TOTAL WORLD	**799.0**		**1 161.1**		**1 446.2**

Notes:

1. Data for the intermediate cost bands are not available for all countries; so regional and global aggregates have not been computed for these categories
2. Source: *Uranium 2005: Resources, Production and Demand*, 2006, OECD Nuclear Energy Agency and International Atomic Energy Agency.

Table 6-3 Uranium: Undiscovered Resources (Prognosticated and Speculative) as of 1 January 2005 (thousand tonnes of uranium [in situ])

	Prognosticated Resources recoverable at			Speculative Resources recoverable at		
	<US$80/kgU	US$80-130/kgU	<US$130/kgU	<US$130/kgU	Cost range unassigned	Total
Egypt (Arab Rep.)					0.1	0.1
Niger	14.5	10.1	24.6			
South Africa	34.9	75.4	110.3		1 112.9	1 112.9
Zambia		22.0	22.0			
Zimbabwe				25.0		25.0
Total Africa	**49.4**		**156.9**	**25.0**	**1 113.0**	**1 138.0**
Canada	50.0	100.0	150.0	700.0		700.0

Table 6-3 Uranium: Undiscovered Resources (Prognosticated and Speculative) as of 1 January 2005 (thousand tonnes of uranium [in situ])

	Prognosticated Resources recoverable at			Speculative Resources recoverable at		
	<US$80/kgU	**US$80-130/kgU**	**<US$130/kgU**	**<US$130/kgU**	**Cost range unassigned**	**Total**
Greenland				50.0	10.0	60.0
Mexico			3.0		10.0	10.0
United States of America	839.0	434.0	1 273.0	858.0	482.0	1 340.0
Total North America	**889.0**		**1 426.0**	**1 608.0**	**502.0**	**2 110.0**
Argentina	1.4		1.4			
Brazil	300.0		300.0		500.0	500.0
Chile			4.1		2.4	2.4
Colombia			11.0	217.0		217.0
Peru	6.6		6.6	19.7		19.7
Venezuela					163.0	163.0
Total South America	**308.0**		**323.1**	**236.7**	**665.4**	**902.1**
China	3.6		3.6	4.1		4.1
India			12.1		17.0	17.0
Indonesia					12.5	12.5
Kazakhstan	290.0	20.0	310.0	500.0		500.0
Mongolia				1 390.0		1 390.0
Uzbekistan	56.3	28.7	85.0		134.7	134.7
Vietnam		7.9	7.9	100.0	130.0	230.0
Total Asia	**349.9**		**418.6**	**1 994.1**	**294.2**	**2 288.3**
Bulgaria	2.2		2.2	16.0		16.0
Czech Republic	0.2		0.2		179.0	179.0
Germany					74.0	74.0
Greece	6.0		6.0			
Hungary		18.4	18.4			
Italy					10.0	10.0
Portugal	1.6	0.4	2.0	5.0		5.0
Romania			3.0	3.0		3.0
Russian Federation	56.3	48.2	104.5	545.0		545.0
Slovenia		1.1	1.1			
Ukraine		15.3	15.3	120.0	135.0	255.0
Total Europe	**66.3**		**152.7**	**689.0**	**398.0**	**1 087.0**
Iran (Islamic Rep.)		4.1	4.1	4.5	6.0	10.5

Table 6-3 Uranium: Undiscovered Resources (Prognosticated and Speculative) as of 1 January 2005 (thousand tonnes of uranium [in situ])

	Prognosticated Resources recoverable at			Speculative Resources recoverable at		
	<US$80/kgU	**US$80-130/kgU**	**<US$130/kgU**	**<US$130/kgU**	**Cost range unassigned**	**Total**
Jordan	37.5		37.5			
Total Middle East	**37.5**		**41.6**	**4.5**	**6.0**	**10.5**
TOTAL WORLD	**1 700.1**		**2 518.9**	**4 557.3**	**2 978.6**	**7 535.9**

Notes:

1. Data for the intermediate cost-bands are not available for all countries; so regional and global aggregates have not been computed for these categories
2. Source: *Uranium 2005: Resources, Production and Demand*, 2006, OECD Nuclear Energy Agency and International Atomic Energy Agency

Table 6-4 Uranium: annual and cumulative production at end-2005 (tonnes of uranium)

	2005 production	**cumulative production to end-2005**
Congo (Democratic Rep.)		25 600
Gabon		25 403
Madagascar		785
Namibia	3 147	84 980
Niger	3 093	97 524
South Africa	674	159 039
Zambia		102
Total Africa	**6 914**	**393 433**
Canada	11 629	397 774
Mexico		49
United States of America	1 039	358 402
Total North America	**12 668**	**756 225**
Argentina		2 631
Brazil	110	2 055
Total South America	**110**	**4 686**

Table 6-4 Uranium: annual and cumulative production at end-2005 (tonnes of uranium)

	2005 production	cumulative production to end-2005
China	750	29 169
India	230	8 423
Japan		84
Kazakhstan	4 357	32 715
Mongolia		535
Pakistan	45	1 016
Uzbekistan	2 300	28 069
Total Asia	**7 682**	**100 011**
Belgium		680
Bulgaria		16 735
Czech Republic	408	109 469
Finland		30
Former Soviet Union (prior to 1992)		377 613
France	6	75 977
Germany	77	219 393
Hungary	4	21 088
Poland		660
Portugal		3 680
Romania	80	18 159
Russian Federation	3 431	38 847
Slovenia		382
Spain		6 156
Sweden		200
Ukraine	800	11 500
Total Europe	**4 806**	**900 569**
Australia	9 519	131 805
Total Oceania	**9 519**	**131 805**
TOTAL WORLD	**41 699**	**2 286 729**

Notes:

1. Data for China, India, Pakistan, Romania, Ukraine and Uzbekistan are estimated
2. The cumulative production shown for Kazakhstan, Uzbekistan, Russian Federation and Ukraine covers only the period 1992-2005 inclusive, as data for earlier years are not available.
3. Source: International Atomic Energy Agency

COUNTRY NOTES

The Country Notes on Uranium have been compiled by the Editors, drawing principally upon the following publication: *Uranium 2005: Resources, Production and Demand* (known as the Red Book)*;* 2006; OECD Nuclear Energy Agency and International Atomic Energy Agency.

Information provided by WEC Member Committees and from other sources has been incorporated when available.

Algeria

Uranium exploration began in 1969, with an aerial radiometric survey in 1971 leading to the identification of numerous promising areas. However, follow-up investigations gradually petered out, and there has been no exploration or prospecting activity in recent years. In-situ RAR at less than US$ 80/kgU have been assessed as 26 000 tonnes U, of which an estimated 75% is recoverable, but no production has ensued.

Argentina

Exploration for uranium started in the early 1950s, since when deposits have been discovered in a number of locations, mostly in the western part of the country and in the southerly province of Chubut in Patagonia. During the 1990s, a countrywide programme of exploration directed at the evaluation of areas with uranium potential was undertaken. Regional assessment of uranium potential continues, with selected areas of interest being studied in greater depth. Several Canadian companies have been involved in exploration activities in recent times.

Uranium was produced on a small scale from the mid-1950s, with cumulative production reaching 2 631 tonnes by the end of 1999. Since then, output has been in abeyance. The production centre at San Rafael in the province of Mendoza, which processed ore from the Sierra Pintada deposit, has been placed on a standby basis. In June 2004, the state agency CNEA, which since 1996 has owned and operated Argentina's uranium industry, presented a proposal to reactivate the San Rafael complex, but in early-2007 a firm decision to reopen the plant had not yet been taken.

Proved reserves of uranium, in terms of RAR recoverable at less than US$ 80/kgU, were 4 880 tonnes at the beginning of 2005. Further Identified Resources comprised 2 200 tonnes of RAR, recoverable at US$ 80-130/kgU and 8 560 tonnes of IR recoverable at less than US$ 130/kgU. Undiscovered resources (at the latter cost level) consisted of 1 440 tonnes of PR.

Australia

Exploration activities between 1947 and 1961 led to a number of uranium discoveries, including the deposits at Mary Kathleen (Queensland), Rum Jungle (Northern Territory) and Radium Hill (South Australia). A decrease in uranium requirements for defence purposes induced a virtual cessation in exploration between 1961 and 1966. Activity picked up again during the late 1960s, as civilian export demand accelerated, and numerous major deposits were located.

In 1983 the Government introduced the so-called 'three mines' policy, which permitted uranium exports only from the Nabarlek, Ranger and Olympic Dam mines. This restrictive measure, with its dampening effect on uranium exploration, lasted until 1996. Exploration expenditure and drilling activity rose in the latter half of the 1990s, but declined to historic lows in 2001 and 2002. Exploratory activity increased sharply in 2003-2005, and was concentrated on parts of the Northern Territory and South Australia.

Australia produced 9 519 tonnes of uranium in 2005, up significantly from previous years' output, bringing cumulative output to more than 131 800 tonnes since 1954. Three uranium production centres were in operation in 2005: Ranger (open-pit mine, production capacity 4 660 tU/yr), Olympic Dam (underground mine at present, possibly also open pit in the future, current production capacity 3 930 tU/yr) and Beverley (in-situ leaching, production capacity 848 tU/yr). In August 2005 BHP Billiton began a two-year environmental assessment of the proposed expansion of its Olympic Dam operation. A new centre with a production capacity of 2 290 tU/yr has been constructed at Jabiluka, but the facility has been on a standby and environmental maintenance basis since 2000. An ISL production centre is planned for the Honeymoon deposit, with production expected to begin in early 2008, according to the owners, sxr Uranium One Inc.

Total Australian production dropped to 7 593 tU in 2006, primarily because of pit flooding and acid-plant problems at Ranger early in the year.

Reasonably Assured Resources (RAR) are reported in the Red Book as 714 000 tonnes at less than US$ 80/kgU and 33 000 tonnes at US$ 80-130/kgU. Inferred Resources (IR) recoverable at these cost levels are 360 000 and 36 000 tonnes, respectively. Compared with the levels in the 2004 Red Book, there were increases at the less-than-US$ 80 level in both RAR and IR, reflecting a revised assessment of the resources at Olympic Dam, the world's largest uranium deposit.

Brazil

Exploration activity over a period of some 40 years, ending in 1991, resulted in the discovery of occurrences and deposits of uranium in eight different areas of Brazil. Total Identified Resources are substantial, consisting of RAR of 157 700 tonnes (recoverable at less than US$ 80/kgU) plus IR of 121 000 tonnes. Undiscovered conventional resources are put at 300 000 tonnes of PR recoverable at under US$ 80/kgU and 500 000 tonnes of SR with no cost range assigned.

Although Brazil's RAR are very substantial, and backed up by massive additional resources, its uranium output has never been on a commensurately large scale: cumulative production at end-2005 was not much more than 2 000 tonnes. Output in 2004 was 300 tU but dropped to 110 tU in 2005 owing to environmental disputes. Mine output recovered to 183 tU in 2006.

After 2 years on standby, the 360 tU/yr Poços de Caldas production centre in Minas Gerais state was definitively shut down in 1997 and is now being decommissioned. It has been replaced by a new plant (now called Caetité) at Lagoa Real in the eastern state of Bahia. The Caetité plant has a current nominal production capacity of 340 tU/yr.

Another production centre, at Itataia in north-eastern Brazil, is scheduled to commence operations in 2007. Its annual uranium production capacity, as a by-product of phosphate output, is planned to be 680 tonnes.

Brazil's conventional resources are supplemented by unconventional resources, for which there are at present no plans for recovery:

- carbonatite (containing 13 000 tonnes U);
- marine phosphates (28 000 tonnes U);
- quartz-pebble conglomerates (2 000 tonnes U).

Canada

Canadian production began in 1942 when uranium was extracted from pitchblende ore from Port Radium, Northwest Territories, which had been mined since the 1930s for its radium content. During the post-war period, uranium deposits were discovered and developed in the Beaverlodge area of northern Saskatchewan and in the Elliot Lake area of Ontario. Demand for uranium increased in the 1960s as the use of nuclear power expanded. After the discovery of large high-grade deposits in the Athabasca Basin in the 1970s, Saskatchewan became Canada's main producer and output from Ontario was gradually phased out, ceasing altogether in 1996.

Canada is the world's largest producer of uranium, with 28% of total world production (2005), about 85% of which is destined for export. In 2005, Canada produced a total of 11 629 tU, valued at over US$ 520 million, all from northern Saskatchewan. This output comes from three production centres, two of which are operated by Cameco Corporation (Key Lake/McArthur River and Rabbit Lake) and the other operated by AREVA Resources Canada Inc. (McClean Lake). The ore is mined from high-grade deposits (up to 23% uranium) which have grades that are one to two orders of magnitude greater than found elsewhere in the world. Production in 2006 appears to have declined by 15% to 9 863 tU.

Two additional mines – Cigar Lake and Midwest - are scheduled to begin production in Saskatchewan in the future. The Cigar Lake Mine is currently being developed and is expected to begin production in 2009. Serious flooding of the underground development area in

October 2006 has delayed the start-up date, which had been scheduled for early-2008. The project leader, Cameco, is devising a comprehensive remediation plan. A proposal to develop the Midwest deposit is undergoing an environmental assessment.

Canada currently holds 9% of world uranium reserves; at 1 January 2006 it had 333 000 tU of RAR at up to US$ 80/kgU and 96 000 tU of IR at less than US$ 80/kgU, while undiscovered resources at below US$ 130/kgU are estimated to be 850 000 tU, of which 150 000 tU are PR and 700 000 tU are SR.

Owing to rising uranium prices, exploration is presently very active in many regions of Canada and the prospects for finding additional resources are excellent.

Chile

Exploration activities have been carried out since the early 1950s, leading to the detection of numerous areas of interest and uranium occurrences. However, no production has so far ensued.

For the 2005 Red Book, Chile has reported in-situ RAR as 748 tonnes and IR as 1 183 tonnes, with no cost ranges assigned. The IAEA/NEA has allocated both amounts to the less than US$ 130/kgU category and assumed a recovery factor of 75% in each case. Undiscovered resources comprise 4 142 tonnes of PR at up to US$ 130/kgU and 2 360 tonnes of SR, with an unassigned cost range.

China

More than 50 years of exploration for uranium have resulted in the discovery of deposits in various parts of the country. The major resources are in Jiangxi and Guangdong provinces in the south-east, in Liaoning province to the northeast of Beijing and in the Xinjiang Autonomous Region of north-western China. In April 2007, it was announced that future uranium exploration would focus on the Yili Basin in Xinjiang and the Ordoo Basin in Inner Mongolia.

Total Identified Resources in ten locations are stated to be 85 000 tonnes (in situ), an increase of 8 000 tU over the level reported for the 2003 Red Book, but with no breakdown by cost category. For the 2005 edition of the Red Book, recoverable RAR at less than US$ 80/kgU have been estimated as 38 019 tonnes and IR in the same cost bracket as 21 704 tonnes. Undiscovered resources have been retained at the 2003 levels of 3 600 tonnes of PR and 4 100 tonnes of SR.

There are five operational production centres, with an aggregate nominal capacity of 840 tU/yr. Construction of a new production centre at Fuzhou is in hand. China, the only producing country in East Asia, does not report official production figures. Production is estimated to have been 730 tU in 2004 and 750 tU in 2005, primarily from underground mining. Given its nuclear power expansion plans and, in order to avoid overdependence on foreign sources of uranium, there are determined efforts under way for further exploration, the development of mines and the improvement of mine productivity.

Colombia

Although no resource data were reported to the IAEA/NEA for their 2005 Red Book, Colombia is still quoted as possessing 11 000 tonnes of uranium in the PR category and 217 000 tU of SR, both amounts on an in-situ basis, at less than US$ 130/kgU. No production of uranium has so far been recorded.

Czech Republic

After an early start in 1946, uranium exploration in the republic was systematic and intensive during a period of more than 40 years. From 1990, however, expenditure decreased sharply, with field exploration coming to an end early in 1994.

There are 23 uranium deposits, of which 20 have been mined-out or closed. The Rozná deposit is being mined and two others may be exploited in the future. The Straz production centre has been closed but some ISL extraction is continuing under a remediation regime. Output from Czechoslovakian mines began in 1946 and until 1990 was all exported to the Soviet Union. Production in 2005 amounted to 408 tonnes, giving a cumulative output of about 109 500 tonnes. The Rozná mine had been scheduled to close in mid-2006 but the sharp increase in the price of uranium means that it can operate profitably until at least the end of 2008.

As a result of the Straz deposit being deemed uneconomic, and of the depletion of resources at the Rozná production centre, RAR declined to 510 tU at the end of 2005 and IR to only 60 tU, both recoverable at up to US$ 80/kgU. Undiscovered resources (on an in-situ basis) comprised 180 tonnes of PR recoverable at up to US$ 80/kgU and 179 000 tonnes of SR, unassigned to a cost category.

Finland

Exploration for uranium took place during the period 1955-1989, resulting in the identification of four uranium provinces. Proved reserves (RAR at US$ 80-130/kgU) amount to 1 500 tonnes, of which 75% is regarded as recoverable. Unconventional resources are represented by possible by-product production of 3 000-9 000 tU from Talvivaara black shales and 2 500 tU from Sokli carbonatite.

Finland's past production of uranium has been limited to the minor quantity (circa 30 tU) produced by a pilot plant at the Paukkajanvaara mine in eastern Finland, which was operated from 1958 to 1961.

Recent years have witnessed a revival of interest in exploration for uranium, with a number of new licences being awarded by the Ministry of Trade & Industry in October 2006 and January 2007.

France

Exploration for uranium commenced in 1946 and during the next 40 years a number of deposits were located. Exploration activities have now ceased and production is confined to small amounts obtained during remediation. Total output in 2005 was only 6 tonnes, bringing the cumulative tonnage to 76 000 tonnes. Since the closure of France's last uranium mine (Jouac) in 2001, RAR have been put at zero; inferred resources are 11 740 tonnes, recoverable at below US$ 130/kgU.

The last French ore-processing plant, at Le Bernardan in the north-western part of the Massif Central, ceased operations in 2001.

Gabon

Exploration by the French Commissariat à l'Energie Atomique (CEA) led to the discovery in 1956 of a substantial deposit of uranium ore near Mounana in south-eastern Gabon. Further deposits in the Franceville Basin were located during 1965-1982. Exploratory activity continued until the late 1990s. Signs of a revival of interest in Gabon’s uranium resources were evident in March 2006 when a press release announced that two Canadian corporations, Cameco and Pitchstone Exploration, had signed an agreement with Motapa Diamonds Inc. to jointly explore Motapa’s uranium exploration licences in the Franceville Basin.

Uranium production from the Mounana production centre began in 1961 and built up to a peak of around 1 250 tpa by the end of the 1970s. Subsequently output followed a declining trend, ceasing altogether in early 1999. The last underground mine, exploiting the Okelobondo deposit (discovered in 1974), closed down in November 1997. An open-pit operation at the Mikouloungou deposit (discovered in 1965) was in production from June 1997 to March 1999, since when Gabon has ceased to be a uranium producer.

Gabon's cumulative production of over 25 000 tonnes of uranium indicates its historic significance as one of the leading minor producers.

Known conventional resources of uranium in Gabon amount to just under 6 000 tonnes, comprising 4 830 tonnes of RAR recoverable at less than US$ 130/kgU, and 1 000 tonnes of IR in the same price category.

Germany

Prior to Germany's reunification in 1990, the GDR had been a major producer of uranium, with a cumulative output of some 213 000 tonnes. All uranium mines have now been closed and the only production relates to uranium recovered in clean-up operations in the former mining/milling areas: 2005 output from this source was 77 tonnes, obtained during the decommissioning of the Königstein mine in Saxony.

Germany’s Identified Resources of uranium total 7 000 tonnes, comprising 3 000 tonnes of RAR recoverable at less than US$ 130/kgU, and 4 000 tonnes of IR in the same price category. Speculative Resources are put at 74 000 tonnes, with their cost range unassigned.

Greenland

Exploration for uranium was carried out for more than 30 years (1955-1986), with moderate success. Fairly sizeable quantities of in-situ uranium resources were reported for Greenland in the 2003 Red Book (there was no national report in the 2005 edition): 27 000 tU of RAR and 16 000 tU of IR, 75% of both being recoverable at US$ 80-130/kgU, together with an in-situ 60 000 tU in the speculative category, most of which was deemed to be recoverable at less than US$ 130/kgU. No production of uranium has yet taken place.

Hungary

Uranium exploration commenced in the early 1950s, with the Mecsek deposit in southern Hungary being discovered in 1954. An underground mine came into production at Mecsek in 1956. Initially the raw ore produced was shipped to the USSR, but from 1963 onwards it passed through a processing plant at Mecsek before being shipped as uranium concentrates.

Mining and milling operations at the Mecsek site were shut down at the end of 1997. Cumulative production of uranium, including a relatively small amount derived from heap leaching, was about 21 000 tonnes. Since 1998, the only production has been of very small quantities (currently about 4 tonnes per year) obtained as a by-product of water treatment activities.

An Australian company, Wildhorse Energy, was granted a uranium exploration licence in January 2007 for its Máriakéménd project in the Pécs region of southern Hungary, in the vicinity of the former Mecsek operation.

Hungary's remaining known conventional resources of uranium, as reported to the IAEA/NEA, are 18 399 tonnes of PR, 75% of which is deemed to be recoverable at less than US$ 130/kgU.

India

Exploration for uranium began in 1949, since when deposits have been located in many parts of the country. Exploratory activity is continuing, with expenditure of around US$ 20 million per annum. Uranium has been produced at the Jaduguda mine in the eastern state of Bihar since 1967. In 2005, output from this and three other mines in the same area (Narwapahar, Bhatin and Turamdih) was some 230 tonnes. The recovery of uranium as a by-product of copper refining has been temporarily suspended.

RAR (with their cost range unassigned) are reported as 54 800 tonnes. Other Identified Resources consist of just over 29 800 tonnes classified as IR, also without an assigned cost range (both were allocated to the less than US$ 130/kgU category in the Red Book). Both these amounts are expressed on an in-situ basis, thus recoverable tonnages would be substantially lower. IAEA/NEA estimates imply average recovery factors of approximately 78% for India’s RAR and about 75% for its IR. Undiscovered conventional resources consist of 12 100 tonnes of PR and 17 000 tonnes of SR. Unconventional resources have been estimated to amount to about 6 600 tonnes, recoverable from copper mine tailings in the Singhbhum district of the state of Jharkhand.

An ion-exchange/acid leaching (IX/AL) plant at Jaduguda processes ore from the Jaduguda, Bhatin and Narwapahar production centres, and is scheduled to process the output of a new underground mine at Bagjata, 30 km to the east. A new IX/AL plant being built at Turamdih will take ore from the adjacent mine as well as from the uranium production centres planned for Banduhurang and Mohuldih. New production centres planned for Lambapur-Peddagattu in Andhra Pradesh and Domiasiat in Meghalaya State will have their own ore-processing facilities at Seripally (IX/AL) and Domiasiat (solvent extraction/acid leaching), respectively.

Indonesia

The Nuclear Minerals Development Centre of the Indonesian National Atomic Energy Agency (BATAN) began exploring for uranium in the 1960s. Since 1996, exploratory work has tended to focus on the vicinity of Kalan in West Kalimantan. Exploration drilling has continued in recent years in a number of locations. No production of uranium has yet taken place.

At the beginning of 2005, Indonesia's RAR, on an in-situ basis and recoverable at less than US$ 130/kgU, amounted to 6 797 tonnes, of which about 7% fell within the less than US$ 80 bracket; Inferred Resources (at up to US$ 130) were 1 699 tonnes, in situ. For both RAR and IR, an estimated 68% was considered to be recoverable. Over and above these amounts, SR were put at 12 481 tonnes.

Iran (Islamic Republic)

Exploratory work has been undertaken for more than 20 years and a number of prospects have been defined, mostly in the central province. However, no production has yet ensued.

Small uranium production centres are planned for construction at Ardakan in central Iran (to use Saghand ore) and Bandar Abbas on the southern coast (to use ore from Gachin).

At the beginning of 2005 RAR (in situ) amounted to 491 tonnes, with IR assessed as 1 436 tonnes, with an estimated 77-78% of both being recoverable at US$ 80-130/kgU. Undiscovered conventional resources (in situ) consisted of 4 050 tonnes in the PR category plus 4 500 tonnes of SR, both recoverable at less than US$ 130/kgU. An additional 6 000 tonnes of SR, with cost range unassigned, was also reported.

Japan

Between 1956 and 1988, the Power Reactor and Nuclear Fuel Development Corporation (PNC) and its predecessor undertook domestic exploration for uranium, resulting in the discovery of deposits at two locations on the island of Honshu. Total discovered reserves, reported as RAR recoverable at up to US$ 130/kgU, were some 6 600 tonnes at the beginning of 2005.

Cumulative production of uranium in Japan amounts to only 84 tonnes, produced by a test pilot plant operated by PNC at the Ningyo-toge mine between 1969 and 1982, together with a small-scale vat leaching test facility from 1978 to 1987.

Jordan

Uranium exploration got under way during the 1980s, since when a number of significant occurrences have been observed. Total Identified Resources are estimated to approach 100 000 tonnes of uranium. On an in-situ basis, Jordan's RAR are put at 37 500 tU and its IR at 60 000 tU, both at a production cost of less than US$ 40/kgU and with an estimated recovery factor of 81%. Prognosticated Resources at up to US$ 80/kgU are estimated to amount to a further 37 500 tU.

By-product resources consist of approximately 70 000 tU associated with phosphate deposits.

Kazakhstan

Uranium exploration commenced in 1948 and since then a large number of ore deposits have been located, initially in the districts of Pribalkhash (in southeastern Kazakhstan), Kokchetau in the north of the republic, and Pricaspian near the Caspian Sea. Since 1970 extensive low-cost resources have been discovered in the Chu-Sarysu and Syr-Darya basins in south-central Kazakhstan.

Production started in 1953, initial output being processed in Kyrgyzstan. Production centres in Kazakhstan were started up by the Tselinny Mining and Processing Company in 1958 (based on underground-mined ore) and by the Kaskor Company in 1959 (based on open-pit mining). Economic pressures forced the closure of the Kaskor plant in 1993 and of the Tselinny plant in 1995. Almost all subsequent uranium production has utilised ISL technology.

At the beginning of 2005 there were six ISL production centres in operation in Kazakhstan, with an aggregate production capacity of 4 700 tU/yr, together with one production centre linked with the Vostok underground mine, with a capacity of 1 250 tU/yr. Total output of uranium in 2005 was 4 357 tonnes, and cumulative national production now exceeds 32 700 tonnes. Provisional data show uranium production rising to 5 279 tonnes in 2006, and there are plans to raise it by over 30% to 6 937 tU in 2007.

Kazakhstan was the 3rd largest producer in 2005, but its RAR of 378 290 tonnes (recoverable at up to US$ 80/kg) put it in a much higher ranking - second only to Australia - and give it a 14.3% share in global resources at that cost level. In addition, there are well over 400 000 tonnes of other identified resources: 135 607 tonnes of other RAR (at US$ 80-130/kgU) and 302 000 tonnes of IR recoverable at costs of less than US$ 130/kgU.

Undiscovered resources (in situ) recoverable at costs below US$ 130/kgU are also massive: 310 000 tonnes of PR and 500 000 tonnes of SR.

The state entity KazAtomProm plans to increase Kazakhstan's uranium production to 15 000 tU/yr by 2010, aiming to make it the world's largest producer. A number of new ISL facilities will be constructed, including several based on joint ventures with foreign corporations. A joint venture (APPAK LLP) with Sumitomo Corp. and Kansai Electric Power Company to construct and operate a mine at West Mynkuduk was established in January 2006. In June, commercial operations commenced at the KATCO joint venture with AREVA, whilst in December the Zarechnoye joint venture with Russia produced its first uranium. Other new mines are planned.

Malawi

Exploration during the 1980s led to the discovery of a uranium deposit at Kayelekera in northern Malawi. The Australian company Paladin Resources Ltd. is currently mounting a project for developing uranium production at Kayelekera, for which it was granted a Mining Licence in April 2007. The mine is scheduled to be commissioned in September 2008 and to reach its full annual production rate of 3.3 million pounds of U_3O_8 during second quarter 2009.

The last Red Book national report (2000) quoted uranium resources in the Kayelekera deposit as amounting to 11 700 tonnes (in situ). They were classified as RAR, 75% of which the IAEA/NEA estimated to be recoverable at less than US$ 80/kgU. No other uranium resources, either identified or undiscovered, were reported.

Mexico

Exploration for uranium came to an end in 1983: at that point, known in-situ resources totalled 2 400 tonnes recoverable at US$ 80-130/kgU, comprising 1 700 tonnes of RAR and 700 tonnes of IR: the IAEA estimates that 75% of these tonnages would be recoverable. Additional undiscovered resources (in situ) amounted to 13 000 tonnes, the bulk of which (10 000 tonnes) were speculative.

Unconventional resources contained in marine phosphates in Baja California amount to about 150 000 tU, as assessed in the early 1980s.

For a short period (1969-1971), molybdenum and by-product uranium were recovered from a variety of ores at a plant in Aldama, Chihuahua state. Uranium output totalled 49 tonnes: there are presently no plans for resuming production.

Mongolia

In-situ resources have been assessed as 61 600 tonnes of RAR and 21 000 tonnes of IR, both at up to US$ 80/kgU, plus 1.39 million tonnes of SR at less than US$ 130/kgU. In assessing recoverable resources, the IAEA/NEA applies a recovery factor of 75% to Mongolia's in-situ RAR and IR tonnages. Despite the considerable size of its Identified Resources, Mongolia’s recorded cumulative production of uranium amounts to only 535 tonnes. The tempo of exploratory activity has increased in recent years. A number of Canadian companies have become involved, either through purchasing prospective areas or by obtaining exploration licences.

Namibia

Although uranium mineralisation had been detected in the Rössing Mountains in the Namib

Desert in 1928, extensive exploration for uranium did not get under way until the late 1960s. The major discovery was the Rössing deposit, located to the north-east of Walvis Bay; other discoveries were made in the same area of west-central Namibia, notably the Trekkopje and Langer Heinrich deposits.

UraMin Inc., a UK/South African company, was granted exploration licences for Trekkopje and the surrounding area in November 2006, and aims to bring a new production facility into production as soon as possible. The Langer Heinrich deposit was acquired by an Australian company, Paladin Resources Ltd., in August 2002. Since then the company has constructed a new mining and processing facility, with a nominal production capacity of 1 000 tU per annum. The processing plant came into operation in December 2006 and is scheduled to reach its designed production rate by mid-2007.

A large open-pit mine operated by Rössing Uranium Ltd (68.58% owned by Rio Tinto Zinc, 3% by the Government of Namibia, 15% by the Government of Iran, 10% by the Industrial Development Corporation of South Africa and the balance by individual shareholders) has been in production since 1976; output in 2005 was 3 147 tonnes, with cumulative production amounting to almost 85 000 tonnes. The 2005 output level represented 79% of the 4 000 tU/yr nominal capacity of Rössing's processing plant. Although Rössing Uranium had intended to close down its operations in 2007, a rise in the price of uranium led to a change of plan. The company is now investing US$ 120 million to extend the mine’s life by ten years, and the facility might stay in operation beyond 2016/2017.

Together, the Rössing and Langer Heinrich mines would confirm Namibia’s position as the top uranium producer in Africa.

The Valencia deposit, lying in the vicinity of the Rössing and Langer Heinrich deposits, was declared uneconomic by Goldfields Namibia, following feasibility studies undertaken in the 1980s. In late-2005 the Canadian company Forsys Metals Corporation acquired the project and now plans to develop an open pit mine by late-2009. At end-March 2007 the results of an environmental impact assessment were awaited.

Namibia is currently the 5th largest uranium producer in the world. Its reasonably assured reserves (at up to US$ 80/kgU) are now put at 151 321 tonnes and are equivalent to nearly 6% of the global total. RAR recoverable at US$ 80-130/kgU are over 31 000 tonnes; Inferred Resources have also been increased and now exceed 123 000 tonnes (in situ), of which almost 100 000 tU would be recoverable at up to US$ 130/kgU.

Niger

Exploration for uranium began in 1956, resulting in the discovery of a number of deposits in the Aïr region of north-central Niger. There are currently two uranium production centres, one near Arlit processing ore from the Ariege, Arlette, Tamou and Taza deposits and operated by Société des Mines de l'Aïr (Somaïr), and the other at Akouta processing ore from the Akouta and Akola deposits and operated by Compagnie Minière d'Akouta (Cominak). Niger's participation in the producing companies is 36.6% in Somaïr, and 31% in Cominak. Both companies continue to carry out exploratory drilling. In 2005-2006, a number of Canadian and Chinese companies were reported to be interested in obtaining exploration concessions in Niger.

Somaïr has been producing uranium from open-pit operations since 1970, while Cominak has carried out underground mining since 1978. The two companies have current production capabilities of 1 500 and 2 300 tU/yr, respectively. Niger's production peaked at 3 245 tU in 2004 before declining to 3 093 tU in 2005. Low productivity has hampered its competitiveness, despite rising uranium prices. Niger is the world's sixth largest producer of uranium, accounting for 7.4% of global output.

The 2005 Red Book features further radical revisions to Niger's uranium resources, compared with the previous edition. RAR recoverable at up to US$ 80/kgU now stand at 180 466 tU, compared with a figure of 102 227 tU in the 2003 book, whilst IR, in the same cost bracket, now show as 44 993 tU recoverable as against 125 377 tU. PR, also in the same cost bracket, are now put at 14 508 tU compared with 9 534 tU, whilst PR at US$ 80-130 amount to 10 100 tU, against zero in the previous edition. Overall, Niger's uranium resources (up to US$ 130/kgU) now total just over 250 000 tU, compared with around 237 000 tU in the 2003 book.

Pakistan

Extensive exploration for uranium has been carried out. Discoveries reported in the 1999 Red Book related to the Kamlial Formation in the Salt Range and the Maraghzar area in the Swat district, but no uranium resources have been reported to the IAEA. A number of previously discovered deposits have been mined out. Production is estimated to be some 40-45 tU per annum. Cumulative output of uranium, all recovered using ISL technology, now exceeds 1 000 tonnes.

Peru

During the course of exploration carried out up to 1992, the Peruvian Nuclear Energy Institute (IPEN) discovered over 40 occurrences of uranium in the Department of Puno, in the south-east of the republic, but no production has taken place.

For the 2005 Red Book, Identified Resources (in situ) in the Macusani area in northern Puno were reported to amount to 3 650 tonnes, of which 1 790 were classified as RAR and 1 860 as IR: 68% of each category was estimated to be recoverable. Undiscovered resources (in situ) consisted of 6 610 tonnes in the PR category (recoverable at less than US$ 80/kgU), plus 19 740 tonnes of SR (recoverable at less than US$ 130/kgU).

Portugal

The first traces of uranium were discovered as long ago as 1907, in association with radium deposits. From the mid-1950s to the mid-1990s, extensive exploration was undertaken, resulting in the discovery of numerous small-to-medium deposits. Starting in 1951, uranium was produced on a relatively small scale for fifty years, mostly at the Urgeiriça mill in north-central Portugal. Operations came to an end in 2001, after cumulative production of almost 3 700 tonnes.

A revised resource assessment in the 2005 Red Book puts RAR (at up to US$ 80/kgU) at 6 000 tonnes, with a further 1 000 tonnes in the US$ 80-130 cost bracket. Other Identified Resources consist of a revised IR level of 1 200 tonnes, recoverable at less than US$ 80/kgU. Undiscovered conventional resources recoverable at below US$ 130/kgU comprise 2 000 tonnes of PR, of which 80% is classed as recoverable at less than US$ 80/kgU, plus 5 000 tonnes of SR.

Romania

Since 1952, when Romania started to produce uranium, cumulative output has exceeded 18 000 tonnes. There are deposits in three principal areas: the Apuseni Mountains in the west, the Banat Mountains in the south-west and the Eastern Carpathians. Since 1978, all of Romania's production of uranium ore has been processed at the Feldioara mill in the centre of the country.

Uranium output in 2005 was approximately 80 tonnes, with RAR (up to US$ 130/kgU) at the beginning of the year estimated as 3 145 tonnes (recoverable). Other Identified Resources recoverable at the same cost level were 3 608 tonnes of IR; in-situ undiscovered resources comprised 3 000 tonnes of PR together with an equal tonnage of SR.

Russian Federation

Uranium exploration has been undertaken since 1944. Over a hundred ore-bearing deposits have been located in 14 districts of the Federation: the Streltsovsk district, where underground mining takes place, the Transural and Vitim districts, where the deposits are suitable for in-situ leaching (ISL), and 11 other districts, where higher-cost resources have been discovered. Government funding for uranium exploration more than doubled in 2005, with the object of stepping-up the search for sandstone-type deposits suitable for the application of ISL technology, as well as for rich unconformity-type deposits suitable for mining.

Mining and processing of uranium ore started in 1951 in the Stavropolsky region of European Russia, a source which had been exhausted by the late 1980s, after producing 5 685 tonnes, of which underground mining accounted for 69% and various leaching techniques for the balance. Between 1968 and 1980, the Sanarskoye deposit in the Transural district produced 440 tonnes of uranium, using ISL technology.

For more than a decade, the most important uranium producing area has been the

Streltsovsk region near Krasnokamensk in the Chitinskaya Oblast of eastern Siberia. The state concern responsible for production in the Krasnokamensk area is the Priargunsky Mining-Chemical Production Association; its production centre has a nominal production capacity of 3 500 tU per annum. Priargunsky accounts for more than 90% of national production. Lower-concentration deposits at the mine are increasingly exploited via block and heap leaching.

In 2002, the Dalur production centre in the Kurgan region started commercial ISL extraction from the Dalmatovskoe deposit. By 2010, it is planned that additional ISL sites at this deposit and at Khokhlovskoe will increase Dalur's annual output to 750 tU. Another production centre, with a nominal output capacity of 1 000 tU per annum, is planned for the Khiagda deposit in the Vitim district of the Buryat Republic.

Total national output in 2005 was 3 431 tU, most of which was derived from ore obtained by underground mining, the balance being obtained from low-grade ore by heap- or in-place leaching. The Russian Federation was the world's fourth largest producer of uranium in 2005, accounting for 8.2% of global output.

Its RAR (estimated to be recoverable at up to US$ 80/kgU) of 131 750 tonnes represented 5.0% of the global total at the beginning of 2005. The balance of Identified Resources recoverable at less than US$ 80/kgU consisted of 40 652 tonnes of IR. Undiscovered resources (in situ) at up to US$ 130/kgU are estimated to be exceedingly large: nearly 105 000 tonnes of PR (over half of which is reckoned to be recoverable at less than US$ 80/kgU), plus 545 000 tonnes of SR.

Slovenia

Exploration of the Zirovski Vrh area began in 1961, followed some 20 years later by the commencement of mining and eventually by the production of yellow cake in 1985. Exploration expenditure ceased in 1990 and uranium production came to an end two years later, with cumulative output of 382 tU.

The reported in-situ uranium resources are fairly modest: RAR of 2 200 tU and IR of 5 000 tU, both recoverable at under US$ 80/kgU, plus 5 000 tU of IR and 1 060 tU of PR, both of which are deemed recoverable at US$ 80-130/kgU. The Red Book estimates that 55% of the Identified Resources (RAR and IR) would actually be recoverable.

South Africa

Between the late 1940s and the early 1970s uranium exploration was pursued as an adjunct to exploration for gold, centred on the quartz-pebble conglomerates in the Witwatersrand Basin in the Transvaal. The 1973-1974 oil crisis triggered intensified exploration for uranium, leading to the country's first primary uranium mine (Beisa) being commissioned in 1981. Output as a by-product of gold mining had begun 30 years previously, and by 1959 26 mines in the Witwatersrand Basin were supplying 17 processing plants, resulting in an annual output of nearly 5 000 tonnes.

Between the late 1980s and the early 1990s, a substantial reduction in production capacity took place; subsequent closures brought the total of operational production centres at the beginning of 2002 down to two, each served by a single mine. The companies in production were Vaal River Operations at Klerksdorp, and Palabora Mining Company in the Northern Province; uranium production by the latter company, as a by-product of copper mining, ceased during the year.

Uranium production in South Africa is a by-product of gold mining and thus highly dependent on the dynamics of the world gold markets. Gold output in South Africa declined by some 20% between 2004 and 2006 and uranium production followed suit: 747 tU in 2004, 674 tU in 2005 and an estimated 640 tU in 2006. Total uranium output in 2005 was the eleventh largest national level in the world. The cumulative output of uranium in South Africa up to the end of 2005 exceeded 159 000 tonnes.

South Africa's uranium production will receive a boost as sxr Uranium One's Dominium mine comes into production during 2007; processing of underground ore had begun by the beginning of March, with the initial annual production rate planned to be 1 460 tU.

The country's RAR (at up to US$ 80/kgU), consisting to a considerable extent of quartz-pebble conglomerates, came to just over 177 000 tonnes by the end of 2005, equivalent to 6.7% of the world total. Further resources are on a commensurately large scale: about 78 000 tU of RAR recoverable at US$ 80-130/ kgU, over 85 000 tU of IR recoverable at up to US$ 130/kgU, 110 000 tU of PR in the same cost range, and more than 1.1 million tU in the speculative category (with no cost range assigned).

Spain

The first uranium discoveries were made in the western province of Salamanca in 1957 - 1958. Subsequently other finds were made further to the south and, in one instance, in central Spain. Production began in 1959 and by the end of 2002, a cumulative total of over 6 000 tonnes had been produced. Ore mining ceased in December 2000 and the production of uranium concentrates was terminated 2 years later. In January 2007 a Canadian company, Mawson Resources, applied for two exploration permits in the La Haba district of Extremadura in south-western Spain.

At beginning-2005, remaining RAR (at less than US$ 80/kgU) were 2 460 tonnes. Further Identified Resources recoverable at US$ 80-130/kgU comprised 2 465 tonnes of RAR and 6 380 tonnes of IR.

Sweden

Exploration for uranium was carried out from 1950 until 1985, when low world prices for the metal brought domestic prospecting to a halt. Four principal uranium provinces were identified, two in south/central Sweden and two in the north. Interest in exploration has revived recently, with the Canadian corporation Mawson Resources Ltd obtaining several concession areas. In April 2007 Mawson reported that drilling had commenced at its Tasjo and Klappibacken projects.

Sweden's proved reserves are reported as 4 000 tonnes of RAR recoverable at less than US$ 130/kgU, with additional amounts recoverable comprising 6 000 tonnes of IR in the same cost bracket.

There are substantial unconventional resources of uranium in alum shale, but the deposits are of very low grade and recovery costs would exceed US$ 130/kgU. During the 1960s, a total of about 200 tonnes of uranium was recovered from alum shale deposits at Ranstad, in the Billingen district of Västergötland, southern Sweden. This mining complex has now been rehabilitated, the open pit being transformed into a lake and the tailings area treated to prevent the formation of acid.

Thailand

Exploration for uranium was carried out from the mid-1970s to the mid-1990s, leading to the discovery of a number of occurrences, mostly in northern Thailand. The in-situ Identified Resources are, however, very small, with RAR amounting to only 4.5 tonnes and IR to about 7 tonnes, both recoverable at up to US$ 130/kgU.

Turkey

The first exploration work took place in 1956-1957, but did not locate any economic deposits. Subsequent activity, which is continuing at the present time, has identified a number of uranium occurrences. In-situ RAR at less than US$ 80/kgU have been assessed as 9 129 tonnes, of which an estimated 81% would be recoverable.

Ukraine

Since the start of exploration for commercial resources of uranium in 1944, a total of 21 deposits have been discovered, mostly located in south-central Ukraine, between the rivers Bug and Dnepr. The most important ore bodies are Vatutinskoye, Severinskoye and Michurinskoye, all in central Ukraine. Uranium has been produced since 1947, initially by the Prednieprovskiy Chemical Plant and since 1959 also by the Zheltiye Vody production centre. The first plant ceased producing uranium in 1990; the 2005 output of the other facility was some 800 tonnes, 80% of its nominal production capacity. All currently processed ore comes from underground operations at the Ingul'skii mine on the Michurinskoye deposit and from the Vatutinskii mine on the Vatutinskoye deposit. In 2005 Ukraine was the ninth largest producer of uranium, accounting for 1.9% of the world total.

Ukraine's uranium resources have been substantially revised for the 2005 edition of the Red Book, largely as a result of a re-assessment of the production costs applicable to the Severinskoye deposit. RAR (at up to US$

80/kgU) are now put at 76 150 tonnes in situ, of which 58 498 is deemed to be recoverable. Further Identified Resources are represented by 10 760 tonnes of in-situ RAR (8 208 recoverable) at US$ 80-130/kgU and 30 070 tonnes of in-situ IR (23 130 recoverable) at up to US$ 130/kgU.

Undiscovered resources (in situ) comprise 15 300 tonnes of PR and 120 000 tonnes of SR (both recoverable at up to US$ 130/kgU), plus 135 000 tonnes of SR (with cost range unassigned).

In separate developments reported in late 2006, an Australian company and a Russian state concern were seeking joint ventures with Ukraine to develop uranium deposits.

United States of America

Between 1947 and 1970 the US Atomic Energy Commission (AEC) promoted the development of a private-sector uranium exploration and production industry; in late 1957 the AEC concluded its own exploration and development activities. Private-sector efforts accelerated in the 1970s in a context of rising prices and anticipated growth in the demand for the metal to fuel civilian power plants.

This exploration activity revealed the existence of extensive ore deposits in the western half of the United States, particularly in the states of Wyoming, Nebraska, Utah, Colorado, Arizona and New Mexico and in the Texas Gulf Coastal Plain. Numerous production centres were erected over the years, but many have now been closed down and either dismantled or put on standby.

Current production is mainly reliant on ISL, although some uranium is obtained from solvent extraction and other operations, such as mine water treatment and environmental restoration. At the beginning of 2005, three ISL plants (with an aggregate capacity of 1 460 tU/yr) and one conventional mill (capacity 210 tU/yr) were operational; one ISL plant and two conventional mills were on standby; one ISL plant was in development and two new facilities were seeking permits and licences. US uranium output in 2005 amounted to an estimated 1 039 tonnes, the eighth highest in the world. Preliminary information indicates that there was a substantial increase in production in 2006 over the previous year's level, reaching 1 586 tU.

The USA's RAR (at up to US$ 80/kgU) at the beginning of 2005 were estimated to be 102 000 tonnes, equivalent to 3.9% of the global total; RAR recoverable at US$ 80-130/kgU were 240 000 tonnes. Prognosticated Resources at up to US$ 80/kgU were 839 000 tonnes, with a further 434 000 tonnes at US$ 80-130/kgU. SR at up to US$ 130/kgU were 858 000 tonnes, with additional SR (with a cost range of US$ 130-260/kgU) amounting to 482 000 tonnes.

Uzbekistan

Deposits of uranium ores have been found in at least 25 locations since the early 1950s, mostly lying in the central Kyzylkum area running from

Uchkuduk in the north-west to Nurabad in the south-east. Although there was some production in the Fergana valley area, starting in 1946, commercial mining began in 1958 at Uchkuduk from open-pit and underground operations. ISL recovery methods were brought into use from 1965 and gradually came to dominate the production scene. The last of the open-pit and underground mines were closed in 1994, after conventional mining had produced a cumulative total of nearly 56 000 tonnes, 65% of which had come from open-pit operations.

Uranium output in 2005 by the state-owned Navoi Mining and Metallurgical Complex (NMMC), the sole producer, totalled about 2 300 tonnes – corresponding to 5.5% of global output. Production is exclusively ISL-based and takes place at eight locations. In operation during 2005 were three ISL production centres, which sent their output by rail to the NMMC processing plant at Navoi (nominal production capacity 3 000 tU/yr).

The republic's in-situ RAR (at up to US$ 80/kgU) amounted to 85 347 tonnes at the beginning of 2005, of which 70% was considered to be recoverable. The balance of known conventional resources consisted of 24 562 tonnes of in-situ RAR (of which 70% was considered recoverable at US$ 80-130/kgU) and 55 129 tonnes of in-situ IR (again with an estimated 70% recoverable, at up to US$ 130/kgU). Undiscovered conventional resources (on an in-situ basis) totalled about 220 000 tonnes, of which PR recoverable at up to US$ 130/kgU accounted for very nearly 85 000 tonnes, the balance (some 135 000 tonnes) being SR without a cost range assigned.

Vietnam

Exploration for uranium in selected parts of the republic began in 1955, and since 1978 a systematic regional programme has been undertaken. Virtually the entire country has now been explored, with a number of occurrences and anomalies subjected to more intensive investigation. Since 1997, exploration activity has been concentrated on the Nong Son basin in the Quang Nam province of central Vietnam.

As at beginning-2005, RAR recoverable at up to US$ 130/kgU (on an in-situ basis) were 1 337 tonnes and IR (on the same basis) 7 244 tonnes: in both categories, about 75% is estimated to be recoverable. Approximately 15% of the IR was reported to fall into the less than US$ 80 cost bracket. Undiscovered in-situ conventional resources recoverable at up to US$ 130/kgU consisted of 7 860 tonnes in the PR category, plus 100 000 tonnes of SR. Further SR (without a cost range assigned) amounted to 130 000 tonnes.

Unquantified amounts of unconventional resources have been reported to be present in deposits of coal, rare earths, phosphates and graphite.

No production of uranium has so far been achieved.

6. Part II: Nuclear

COMMENTARY

COMMENTARY

Nuclear Power Today

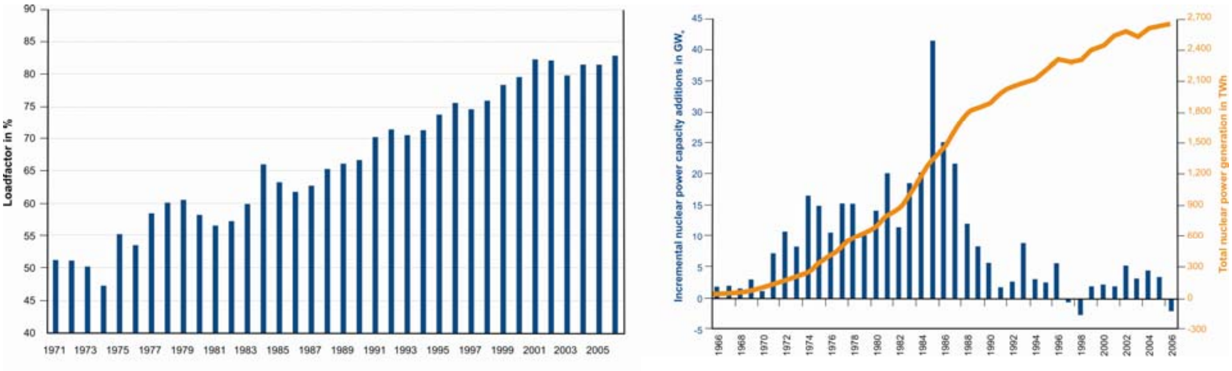
Nuclear Power Plants in Operation and Under Construction

Worldwide, at the beginning of 2007, there were 435 nuclear power reactors in operation, totalling 367 GW_e of generating capacity. In 2005 nuclear power supplied about 16% of the world's electricity. Data for 2006 are likely to show a decrease in this percentage, as retirements during the year exceeded new capacity brought on line, while total electrical generating capacity (nuclear power plus all other sources) continued to grow at almost 4% per year. The world's fleet of nuclear power reactors maintained a high average availability factor of 83% (Fig. 6-8) which in 2006 allowed a record production of 2 658 TWh. Moreover, the past increase in availability factors that has helped keep the nuclear share relatively stable for the last 15 years, despite limited investment in new build, appears currently to have plateaued.

Two new reactors were connected to the grid in 2006, one in China and one in India. This compares with four new connections in 2005 (plus the reconnection of one laid-up reactor) and five new connections in 2004 (plus one reconnection). There were eight nuclear power reactor retirements in 2006: the two Kozloduy Units 3 & 4 in Bulgaria and Bohunice-1 in Slovakia, in compliance with the accession arrangements with the European Union, the UK's four oldest reactors at Dungeness A and

Figure 6-8 Average availability of the world's fleet of nuclear power plants (left) and incremental nuclear generating capacities and nuclear electricity generation (right).

Source: IAEA



Sizewell A after more than 40 years of operation, and José Cabrera-1 in Spain. This compares with two retirements in 2005 and five in 2004. The resulting net decrease in global nuclear generating capacity during 2006 was 806 MW_e.

Using the International Atomic Energy Agency (IAEA) definition that construction begins with the first pouring of concrete, there were three construction starts in 2006: Lingao-4 (1 000 MW_e) and Qinshan II-3 (610 MW_e) in China, and Shin Kori-1 (960 MW_e) in the Republic of Korea. In addition, active construction resumed at Beloyarsk-4 in Russia.

Nuclear Capacity Expansion

Current expansion, as well as near-term and long-term growth prospects, remains centred in Asia. Of the 31 reactors under construction at end-2006, 17 were in Asia and 26 of the last 36 reactors to have been connected to the grid were likewise in Asia. Increased nuclear capacity in some countries (e.g., the USA, Belgium, Finland, Spain, Sweden, Switzerland and Germany) is the result of uprating existing plants, which can add up to 20% of additional capacity - a highly cost-effective way of bringing new capacity on-line.

In 2006, the US Nuclear Regulatory Commission (NRC) approved eight more licence renewals of 20 years each (for a total licensed life of 60 years for each nuclear power plant), bringing the total number of approved licence renewals to 47 at the end of the year. In the USA there are proposals for over 20 new reactors and the first combined construction and operating licences for these are likely to be applied for in 2007. In the Netherlands, the Government granted a 20-year extension to the Borssele nuclear power plant for a total licensed lifetime of 60 years. The Government also set conditions for new nuclear plants, a shift from the country's earlier nuclear power phase-out policy. The French Nuclear Safety Authority (ASN) conditionally cleared twenty 1 300 MW_e Pressurised Water Reactors (PWR) belonging to Electricité de France (EDF) for an additional ten years of operation, for a total currently licensed period of 30 years. As well, in May 2006 EDF gave the go-ahead for the construction of a 1 600 MW_e European Pressurised Water Reactor (EPR) unit at Flamanville at an estimated cost of € 3.3 billion. The Flamanville site already hosts two 1 330 MW_e PWRs. In Canada, Point Lepreau received a three-year licence renewal for the period 2009-2011.

The completion date of the project of Teollisuuden Voima Oy (TVO) to build an EPR at the Olkiluoto site in Finland - the first nuclear power plant ordered in Western Europe for 15 years - has been put back by over a year.

Delays have been caused by the concrete used in the new unit's foundations not being in conformity with the specification, as well as delivery problems with subcontractors. Observers suggest that the problems faced in building Olkiluoto-3 are common for a first-of-a-kind plant, especially when most of the subcontractors involved have not worked to

Figure 6-9 Nuclear power reactors total operating experience to 31 December 2006

Source: International Atomic Energy Agency, Power Reactor Information System, http://www.iaea.org/programmes/a2/index.html

Country	Years	Months	Country	Years	Months
Argentina	56	7	Mexico	29	11
Armenia	32	6	Netherlands	62	0
Belgium	212	7	Pakistan	41	10
Brazil	31	3	Romania	10	6
Bulgaria	141	3	Russian Federation	901	4
Canada	527	1	Slovakia	118	7
China	66	7	Slovenia	25	3
Czech Republic	92	10	South Africa	44	3
Finland	111	4	Spain	245	6
France	1523	2	Sweden	342	6
Germany	700	5	Switzerland	158	10
Hungary	86	2	Taiwan, China	152	1
India	267	7	Ukraine	323	6
Japan	1276	7	United Kingdom	1400	8
Korea (Republic)	279	8	United States of America	3 187	6
Lithuania	40	6	**Total ***	**12 597**	**5**

* Includes reactor years for Italy and Kazakhstan which no longer operate nuclear power plants

nuclear standards for many years, if at all. It is of the utmost importance to build on the lessons learned for future construction projects.

Rising Expectations

Fossil Fuel Prices. Higher world market prices for fossil fuels have put nuclear power on the agenda of many countries currently without nuclear power and have revived interest in countries with stagnating nuclear power programmes. Because they are driven largely by demand, current high prices for fossil fuels are likely to be more permanent than were those of the 1970s. Energy demand growth, driven by continuing economic development, is expected to persist - hence the pressure on prices is likely to last. High world market prices for fossil fuels have the greatest impact on countries that are highly dependent on energy imports, particularly developing countries with relatively scarce financial resources. A doubling of international prices translates into generation cost increases of about 35–45% for coal-fired electricity and 70–80% for natural gas. In contrast, a doubling of uranium prices (which have also increased recently — see below) increases nuclear generating costs by only about 5%.

Rising fossil fuel and uranium prices not only affect the relative competitiveness of electricity generating options but can also affect supply security. Concerns about energy supply security were important in the nuclear expansion programmes of France and Japan at the time of the 1970s oil shocks. They are one of the arguments advanced in Europe today for expanding nuclear power, and they may prove an important motivation for some countries currently without nuclear power to strongly consider the possibility.

Developing countries with sizable domestic fuel resources have recently begun looking at the feasibility of introducing nuclear power in the 2015–2020 time frame. These include OPEC members Indonesia and Nigeria as well as six member countries of the Gulf Cooperation Council. For them the immediate impact of increased oil prices is not the same as that for oil importers, but the logic may lead in the same direction. Nuclear power can be a vehicle to increase export revenues by substituting domestic demand for natural gas (and to a lesser extent oil) by nuclear power. The additional export earnings may well finance the construction of part or all of a country's first nuclear power plants. Also some oil and gas exporters, for example Indonesia, may be interested in nuclear power as a way to reduce currently high rates of oil and gas resource depletion.

Economics. Nuclear power plants have a 'front-loaded' cost structure, i.e. they are relatively expensive to build but relatively inexpensive to operate. The low share of uranium costs in total generating costs protects plant operators against resource price volatility. Thus existing well-run operating nuclear power plants continue to be a generally competitive and profitable source of electricity, but for new construction the economic competitiveness of nuclear power depends on several factors. Firstly, it depends on the alternatives available: some countries are rich in alternative energy resources, others less so. Secondly, it depends on the overall electricity demand in a country and how fast it is growing. Thirdly, it depends on the market structure and the investment environment. Other things being equal, nuclear power's 'front-loaded' cost structure is less attractive to a private investor in a liberalised market that values rapid returns, than to a government that can look longer-term, particularly in a regulated market that assures attractive returns. Private investments in liberalised markets will also depend on the extent to which energy-related external costs and benefits (e.g. pollution, greenhouse gas (GHG) emissions, waste and energy supply security) have been internalised. In contrast, government investors can incorporate such externalities directly into their decisions. Also important are regulatory risks. Political support for nuclear power varies across countries, and, within a given country, it can change over time. An investor must weigh the risk of political shifts that might require cancellation of the project midstream or introduce delays and costs that would vitiate an originally attractive investment. Different countries also have different approval processes. Some are less predictable than others and create greater risks, from the investor's perspective, of expensive interventions or delays.

In Japan and the Republic of Korea, the relatively high cost of alternatives benefits nuclear power's competitiveness. In India and China, rapidly growing energy needs encourage the development of all energy options. In Europe, high electricity prices, high natural gas prices and limitation of GHG emissions under the European Union Emission Trading Scheme (EU ETS) have all improved the business case for new nuclear power plants. In the USA, the 2005 Energy Act significantly strengthened the business case for new construction. Previously new nuclear power plants had not been an attractive investment, given plentiful low-cost coal and natural gas, no GHG emission limits, and investment risks arising from the lack of recent experience in licensing new nuclear power construction. The provisions of the Energy Act, including loan guarantees, government coverage of costs associated with certain potential licensing delays and a production tax credit for up to 6 000 MW_e of advanced nuclear power capacity, have improved the business case enough to prompt announcements by nuclear firms and consortia of possible Combined Operating License (COL) applications covering approximately 25 possible new reactors in the USA.

Figure 6-10 The ranges of levellised costs associated with new construction as estimated in seven recent studies for electricity generating technologies in different countries
Source: IAEA

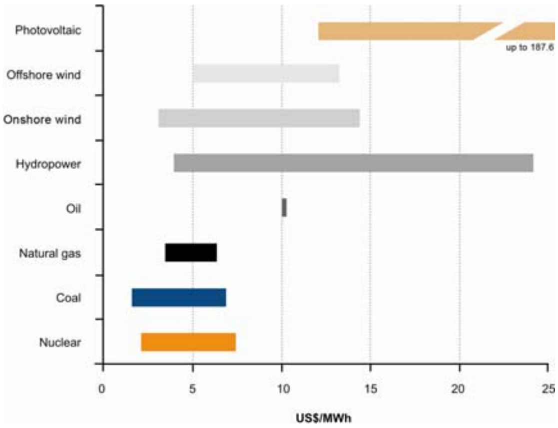


Figure 6-11 Life-cycle GHG emissions from different electricity generating chains
(Energy storage technologies include: compressed air, pumped hydro, battery systems)
Source: Weisser, 2007

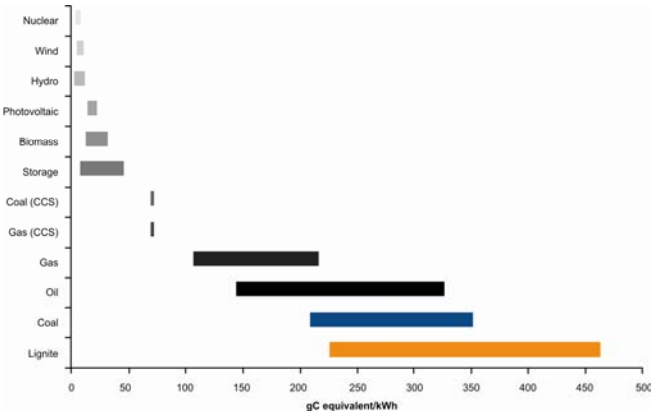


Fig. 6-10 summarises estimates from seven recent studies of electricity costs for new power plants with different fuels. Except for oil-fired electricity generation (estimated in only one study) the high end of each cost range is at least 100% higher than the low end. This is due partly to different techno-economic assumptions across the studies, but also to the factors listed above. Moreover, the ranges in Fig. 6-10 incorporate only internalised costs. If high enough priority is given to improving national energy self-sufficiency, for example, the preferred choice in a specific situation might not be the least expensive.

Energy Security. The best way to strengthen a country's energy supply security is by increasing the number and resiliency of energy supply options, and for many developing countries, expanding nuclear power would increase the diversity of energy and electricity supplies. Moreover, nuclear power has two features that generally further increase resiliency. The first was noted above: that nuclear electricity generating costs are much less sensitive to changes in resource prices than are fossil-fired electricity generating costs. Secondly, the basic fuel, uranium, is available from diverse producer countries, and small volumes are required, making it easier to establish strategic inventories. In practice, the trend over the years has been away from strategic stocks towards supply security based on a diverse well-functioning market for uranium and fuel supply services. But the option of relatively low-cost strategic inventories remains available for countries that find it important.

Environment. Environmental considerations may weigh increasingly in favour of nuclear power. Nuclear power at the point of electricity generation does not produce any emissions that damage local air quality, cause regional acidification or contribute to climate change. There are some emissions associated with plant construction and the nuclear fuel cycle (i.e. mining, enrichment, transportation, etc.). But on a per kWh basis over the lifetime of the plant these are far below emissions from fossil-fired power plants and at least comparable to those of wind power and biomass conversion (Fig. 6-11).

The Kyoto Protocol, which entered into force in February 2005, requires most developed countries to limit their GHG emissions in the 'first commitment period', 2008–2012. Before the Protocol's entry into force, nuclear power's advantage of very low GHG emissions was largely invisible to investors, as the lack of restrictions or taxes on such emissions meant there was no economic value to their avoidance. Different countries have adopted different policies to meet their Kyoto Protocol limits. Not all benefit nuclear power despite its low GHG emissions, but in the longer run, the limits on GHG emissions should make nuclear power increasingly attractive. For example, a charge on carbon dioxide emissions of € 20 per tonne of

For many developing countries, expanding nuclear power would increase the diversity of energy and electricity supplies.

carbon dioxide (tCO_2), would improve a nuclear plant's generating costs relative to those of a modern coal-fired plant by 10-20%. During 2006, CO_2 traded in Europe between € 6 and € 29 per tCO_2.

With respect to emission reductions after the first commitment period, the 11th session of the Conference of the Parties to the United Nations Framework Convention on Climate Change (COP11) in 2005 decided to start discussions in an ad-hoc working group, which has now met twice, in May and November 2006. Discussions are still in an early phase, and have not yet begun to address specific issues such as the current exclusion of nuclear power projects from the clean development mechanism and joint implementation.

Political and Public Acceptance. Rising expectations for nuclear power are also founded on positive government statements about, and newly-expressed interest in, the technology. In March 2005 high-level representatives of 74 governments, including 25 representatives at the ministerial level, gathered in Paris at a conference organised by the IAEA to consider the future role of nuclear power. The vast majority of participants affirmed that nuclear power can make a major contribution to meeting energy needs and sustaining the world's development in the 21st century, for a large number of both developed and developing countries. A meeting organised by the IAEA in December 2006 to examine Issues for the Introduction of Nuclear Power was attended by 28 countries that currently do not operate nuclear power plants.

Factors contributing to the rise in expectations are nuclear power's good and lengthening track record, the persistent growth in global energy needs, new environmental constraints, concerns in some countries about energy supply security and specific nuclear power expansion plans in countries such as India, China, Japan, the Republic of Korea and the Russian Federation. Nuclear power's good and lengthening track record is reflected in the more than 12 400 reactor-years of experience to date, improved capacity factors, lower generating costs and an excellent safety record.

There has been one accident with major off-site consequences — at Chernobyl in 1986. That accident cost lives and caused widespread misery. But it also brought about major changes including the founding of a 'safety culture' of constant improvement, thorough analysis of experience and sharing of best practices. This safety culture has been demonstrating its effectiveness for nearly two decades, and the resulting safety record provides the basis for countries considering constructing nuclear power plants.

Public policies and public opinion towards nuclear power development remain divided - especially in Europe. While some countries vigorously support nuclear development, others have either placed a total ban on atomic energy (Austria, Denmark, Ireland) or have legislated nuclear phase-out policies (Sweden, Belgium,

Figure 6-12 Aggregate results of a global public opinion poll
Source: IAEA 2005

Germany). A recent global public opinion survey commissioned by the IAEA shows a continuing diversity of views. The survey polled 18 000 people in 18 countries. There was substantial diversity across countries. Aggregated results are shown in Fig. 6-12. A majority of 62% wished to keep current plants running at the same time as a majority of 59% did not want new plants built. A follow-up question was also asked that included brief information about nuclear power's very low greenhouse-gas emissions, following which the percentage in favour of expanding nuclear power rose from 28% to 38%, and the percentage opposing expansion dropped from 59% to 47%.

Public policies with regard to nuclear power plants often reflect the views of the public, but this is not always the case. Recently the mood has been changing, and more positive attitudes towards nuclear power are emerging in some countries. For example, in the United Kingdom a positive public attitude towards nuclear power is becoming evident, and the UK Government has indicated its belief that nuclear has a rôle to play. In its 2007 Energy White Paper it presented its 'preliminary view' that the private sector should be allowed to construct and operate new nuclear stations. According to a Mori opinion poll of 1 500 people conducted in early 2006, 54% said they would accept new nuclear power stations if they would help fight climate change. And 48% agreed that the nation needs nuclear power because renewables alone are not able to meet its electricity needs. Polls also found that pitting nuclear power against renewables hurt support for nuclear power while a combination of both often appeared quite acceptable.

In Poland, where nuclear development was halted by a Parliamentary decision in 1990, the Council of Ministers approved a draft energy policy in early 2005 that explicitly includes nuclear power.

Reflecting these recent positive political developments in Europe, a cross-party group of 25 EU members of parliament endorsed the vital contribution of nuclear energy in countering climate change and called for more investment in all low- or zero-carbon power generation technologies. They said nuclear power should remain central to the EU's energy and environmental policy planning, and called for a global strategy to address climate change.

In the United States, public support for the continued use of nuclear energy now stands at a record high of 70% and shows a continued upward trend, according to a new opinion poll conducted for the US Nuclear Energy Institute (NEI).

Uranium Availability

The world uranium market is rapidly adjusting to 'rising expectations'. The ten-fold uranium price increase since 2000 is one indicator of this adjustment and triggered the beginning of a correction of an almost twenty-year old market anomaly, in which mine production persistently fell short of reactor requirements. Exploration and mine development have begun to follow uranium prices, with the number of exploration and mining companies mushrooming ten-fold and exploration expenditures increasing four-fold between 2001 and 2006. Short- and long-term uranium resource availability is discussed in detail in Chapter 6, Part I Uranium. Suffice it to say here that uranium resources are plentiful and pose no constraint on future nuclear power development.

Spent Fuel and Reprocessing

Annual discharges of spent fuel from the world's reactors total about 10 500 metric tonnes of heavy metal (t HM) per year. Two different management strategies are being implemented for spent nuclear fuel. In the first strategy, spent fuel is reprocessed to extract usable material (uranium and plutonium) for new mixed oxide (MOX) fuel (or stored for future reprocessing). Approximately one-third of the world's discharged spent fuel has been reprocessed. In the second strategy, spent fuel is considered as waste and is stored pending disposal. Based now on more than 50 years of experience with storing spent fuel safely and effectively, there is a high level of confidence in both wet and dry storage technologies and their ability to cope with rising volumes, pending implementation of final repositories for all high-level waste.

As of today, China, France, India, Japan, the Russian Federation and the UK either reprocess, or store for future reprocessing, most of their spent fuel. Canada, Finland, Sweden and the USA have currently opted for direct disposal, although in February 2006, the USA announced a Global Nuclear Energy Partnership (GNEP) initiative, which includes the development of advanced recycling technologies for use in the USA.

Most countries have not yet decided which strategy to adopt. They are currently storing spent fuel and keeping abreast of developments associated with both alternatives.

In March 2006, final testing for the commissioning of Japan's new Rokkasho reprocessing plant began and is expected to take 17 months. The Rokkasho plant's final product is a MOX powder, which was produced for the first time in November. Commercial-scale production of MOX powder is expected in the second half of 2007. The plant's maximum reprocessing capacity will be 800 tonnes of uranium per year, enough to reprocess 80% of Japan's annual spent fuel production. In China non-radioactive commissioning was completed for the country's first experimental reprocessing plant. Development of new recycling processes is also taking place, e.g. the UREX+ process in the USA to recycle spent nuclear fuel, without separating out pure plutonium, and fabricate the separated transuranic elements into fuel for fast advanced burner reactors.

In 2006, approximately 180 tonnes of civil origin MOX fuel were loaded on a commercial basis in more than 30 PWRs and two Boiling Water Reactors (BWRs) in Belgium, France, Germany and Switzerland. The share of MOX fuel assemblies in the core varied from 25% to 50%. No substantial increase in MOX fuel requirements is expected until 2010, when Japan plans to start its 'pluthermal' programme to load MOX fuel in 16 to 18 power reactors. In India, some 50 MOX fuel bundles have recently been irradiated in a Pressurised Heavy Water Reactor (PHWR 220) on an experimental basis.

Belgonucleaire's MOX fuel plant in Dessel ceased production in August 2006, with decommissioning scheduled for completion by 2013. As a result of this, there remain only two significant MOX fuel fabricators: France and the UK.

Waste and Decommissioning

The Finnish, Swedish and US repository programmes continue to be the most developed, but none is likely to have a repository in operation much earlier than 2020. The world's one operating geological repository is the Waste Isolation Pilot Plant (WIPP) in the USA. Since 1999, it has accepted long-lived transuranic waste generated by research and the production of nuclear weapons, but no waste from civilian nuclear power plants. In 2006 the US Environmental Protection Agency approved WIPP's first recertification application, submitted in 2004. Recertification is required every five years. France's new legislation on spent-fuel management and waste disposal, which established spent-fuel reprocessing and recycling of usable materials as French policy, also established deep-geologic disposal as the reference solution for high-level long-lived radioactive waste. The legislation sets goals of applying for a licence for a reversible deep geological repository by 2015 and of opening the facility by 2025. It also calls for operation of a fourth-generation prototype fast reactor by 2020 to test, among other tasks, transmutation of long-lived radioisotopes. Also in 2006, the UK's Committee on Radioactive Waste Management concluded that the best disposal option for the UK is deep geological disposal, with 'robust interim storage' until a repository site is selected.

In November 2006 the Swedish nuclear fuel and waste management company SKB applied to the Swedish nuclear power inspectorate for a permit for an encapsulation plant in Oskarshamn. The encapsulation plant is the first step towards final disposal using the KBS-3 method, in which fuel is encapsulated in copper canisters and deposited in bedrock at a depth of approximately 500 metres. A final ruling on the application is not expected until after 2009, when the application for a final deep geological repository is scheduled to be submitted. Site investigations for a final repository are being carried out near Forsmark in Osthammar and in the Laxemar area of Oskarshamn.

Following a three-year nation-wide consultative process, Canada's Nuclear Waste Management Organization recommended an 'adaptive phased' approach to managing Canadian spent fuel. During the next 30 years, whilst spent fuel would continue to be stored at reactor sites, a suitable site for a deep geological repository would be selected, and a decision would be made as to whether to also construct a centralised interim shallow underground storage facility to start receiving spent fuel (in about 30

Figure 6-13 Unplanned scrams per 7 000 hours critical
Source: WANO 2006 Performance Indicators

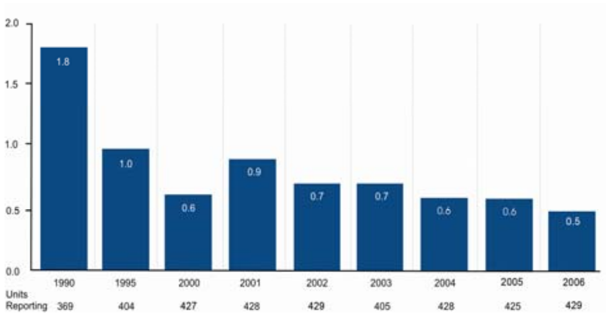
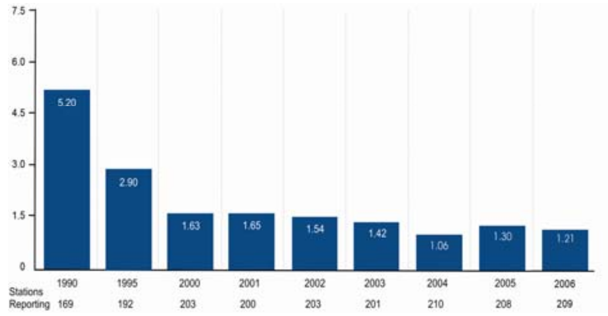


Figure 6-14 Industrial accidents at nuclear power plants per 1 million person-hours worked
Source: WANO 2006 Performance Indicators



years' time). With or without a centralised interim facility, the deep repository would begin accepting spent fuel in about 60 years.

Decommissioning was completed in 2006 at the Big Rock Point nuclear power plant site in the USA, and the site returned to greenfield status. Thus, as of 2006, nine power plants around the world had been completely decommissioned, with their sites released for unconditional use. Seventeen plants have been partially dismantled and safely enclosed, 30 are being dismantled prior to eventual site release, and 30 are undergoing minimum dismantling prior to long-term enclosure.

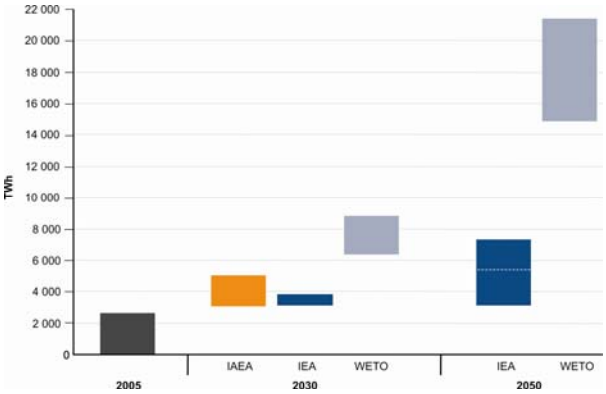
Safety

The international exchange of nuclear power plant operating experience and, in particular, the broad dissemination of 'lessons learned' are essential parts of maintaining and strengthening the safe operation of nuclear power plants. Collecting, sharing and analysing operating experience are all vital safety-management elements, and there is clear empirical evidence that learning from nuclear power plant operating experience has led, and continues to lead, to improvements in plant safety. International mechanisms to facilitate exchange include the World Association of Nuclear Operators (WANO) and the IAEA. Regular meetings of the IAEA–OECD/NEA Joint Incident Reporting System are an additional part of this global exchange process, where recent incidents can be discussed and analysed in detail. Safety indicators, such as those published by WANO and reproduced in Figs. 6-13 and 6-14, improved dramatically in the 1990s. However, in recent years some areas of improvement have stalled. Moreover the gap between the best and worst performers is still large, providing substantial room for continuing improvement. Since the 1986 accident at Chernobyl, enormous efforts have been made to upgrade reactor safety features, but facilities still exist at which nuclear safety assistance should be made a priority.

Proliferation Resistance

At the 2005 Non-Profileration of Nuclear Weapons (NPT) Review Conference, the IAEA Director General proposed seven steps to strengthen the non-proliferation regime: reaffirm the goal of eliminating nuclear weapons; strengthen the Agency's verification authority; establish better control over proliferation-sensitive parts of the fuel cycle; secure and control nuclear material (e.g. strengthen the Convention on the Physical Protection of Nuclear Material and minimise highly-enriched uranium in civilian use); demonstrate a commitment to nuclear disarmament; strengthen the NPT non-compliance mechanism; and address real national security concerns. Six of the seven do not directly address nuclear power – it is not a principal source of proliferation risk. The one that does address nuclear power proposes tighter control over proliferation-sensitive elements of the nuclear fuel cycle, specifically enrichment and reprocessing, while assuring the supply of nuclear fuel for peaceful uses.

Figure 6-15 Global nuclear electricity generation in 2005 and the ranges of projections for 2030 and 2050 from four studies
Source: IAEA



Except for 2005, the bottom part of each bar corresponds to the respective 'low' or 'reference projections'; the top of each bar to the 'high', 'accelerated policy' or 'carbon constraint/hydrogen scenarios'

Projected Growth for Nuclear Power

In 2006, updated projections of nuclear power expansion in the period to 2030 were published by the IAEA (2006b), and by the International Energy Agency (IEA) in its *World Energy Outlook (WEO) 2006* (IEA, 2006). The IAEA provides a high and a low projection for nuclear power. The *World Energy Outlook 2006* includes a reference scenario plus an alternative scenario that assumes additional measures to enhance energy security and mitigate CO_2 emissions.

In 2005, the IEA published an additional study with seven scenarios extending to 2050 (IEA, 2005). These include a baseline scenario and six 'accelerated technology scenarios' (ACTs). The ACTs examine technological options to limit or reverse global growth in CO_2 emissions and oil consumption.

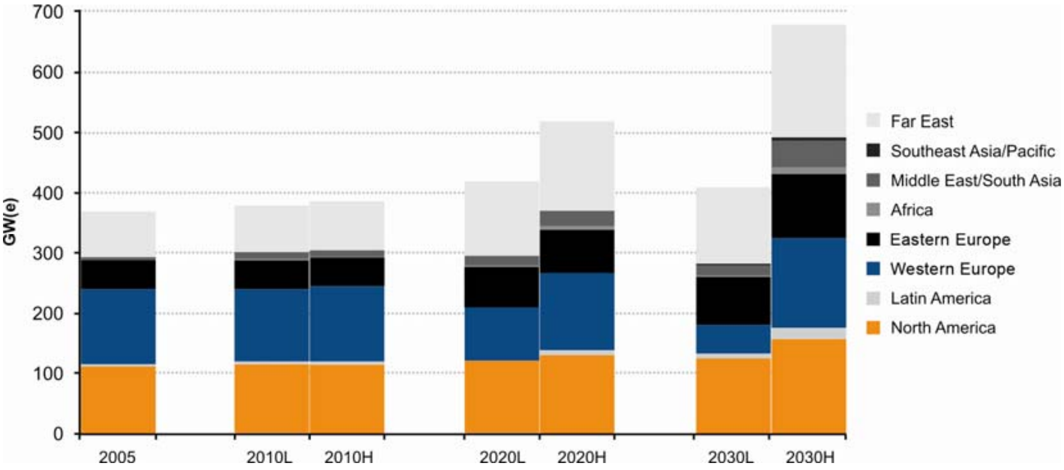
In early 2007, the European Commission (EC) published the *World Energy Technology Outlook – 2050 (WETO-H$_2$)*, (EC, 2006). Built on a business-as-usual or reference case, WETO H_2 analyses two specific scenarios that reflect political objectives for mitigating climate change and promoting new clean energy technologies. A 'carbon constraint case' explores the consequences of more ambitious carbon-emissions policies that aim at the long-term stabilisation of atmospheric CO_2 concentrations. The 'hydrogen case' builds on the 'carbon constraint case' and explores a series of scientific breakthroughs that significantly increase the cost-effectiveness of hydrogen technologies.

The four publications thus include, altogether, fourteen scenarios. Their projections for nuclear power are summarised in Fig. 6-15. The bars in Fig. 6-15 show the spread between the 'low' (IAEA), reference scenario (IEA) and reference case (WETO) nuclear electricity projections – the bottom of the respective bars – and the 'high' (IAEA), 'accelerated policy' (IEA) and 'carbon constraint/hydrogen scenarios' (WETO).

In Fig. 6-15 the IAEA low projection assumes that no new nuclear power plants are built beyond what is under construction or firmly planned today and old nuclear power plants are retired on schedule. Nuclear electricity generation in this projection grows to just 3 100 TWh in 2020 (1.1% growth per year) and remains essentially unchanged in the period to 2030. The IAEA high projection incorporates additional reasonable planned and proposed nuclear projects beyond those already firmly in the pipeline. It shows steady growth to 5 040 TWh in 2030 (2.6% growth per year). Fig. 6-16 shows the nuclear capacity developments by major region for the IAEA high and low projections.

Fig. 6-16 shows that the global aggregates in Fig. 6-15 mask regional differences, particularly in the low projection. Nuclear electricity generation in Western Europe in the low projection drops by almost 60% between 2005 and 2030, as projected retirements consistently outpace new construction. But nuclear power generation in the Far East grows by 80% and in Eastern Europe by almost 50%. In the high projection, nuclear generation grows in all

Figure 6-16 Nuclear capacity projections of the IAEA low (L) and high (H) scenarios
Source: IAEA



regions. In both projections, new construction is greatest in the Far East, Eastern Europe, North America and the Middle East/Southeast Asia, in that order.

The IEA WEO reference scenario is a 'business-as-usual' scenario that assumes the continuation of current policies and trends. Projected nuclear electricity generation in this scenario is almost identical to that in the IAEA low projection. The measures in the alternative scenario to enhance energy security and mitigate CO_2 emissions are expected to boost nuclear electricity generation but, as shown in Fig. 6-15, not enough to match the IAEA high projection.

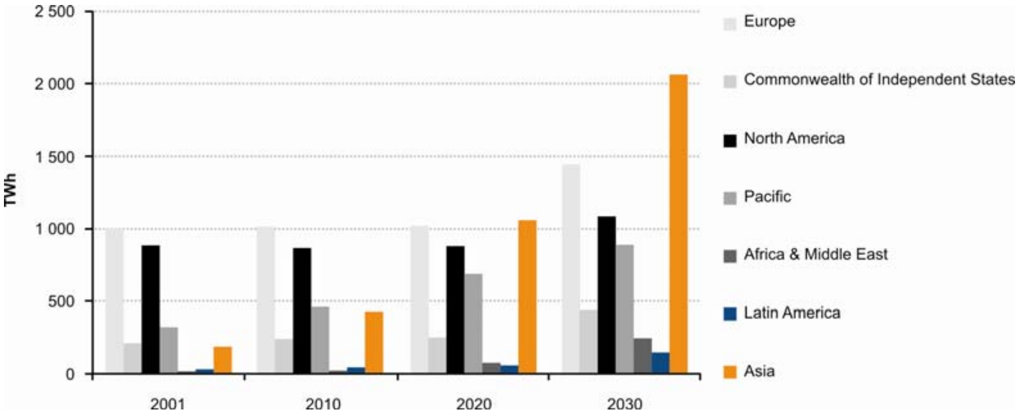
The EC WETO reference case foresees a much faster expansion of nuclear-generated electricity - the 6 300 TWh by 2030 is approximately twice the amount projected by both IEA and IAEA. While in the IAEA and IEA scenarios nuclear's share declines to 12-13% (IAEA) and 10% (IEA), the WETO cases project, after some decline by 2020, a return to the 16-17% market share observed between the early 1990s and 2005. Although the reference case is essentially a continuation of existing economic and technological trends, the short-term constraints on the development of oil and gas production, a receding public reservation against nuclear power and the implementation of moderate climate policies lead after 2020 to a strong expansion of nuclear power for its climate-friendly characteristics and for reasons of energy security (Fig. 6-17).

The 'carbon constraint' case involves only marginally higher nuclear electricity generation than the reference case, but nuclear's share approaches 19% owing to the lower global demand for electricity in an inherently more energy-efficient world economy. A world that develops, commercialises and adopts hydrogen end-use technologies as well as supply infrastructures would boost demand for nuclear electricity to more than 8 800 TWh (top of the WETO bar for 2030 in Fig. 6-15) or 1 200 GW_e installed capacity by 2030.

For the IEA scenarios to 2050, (Fig. 6-15) the low end of the range is defined by the baseline scenario and a 'low nuclear scenario'. These are essentially extensions of the WEO 2006 reference scenario. The high end of the range is set by the TECH Plus scenario, which assumes accelerated cost reductions for fuel cells, renewables, biofuels and nuclear power. In this scenario, nuclear electricity generation continues to grow to 2050 at essentially the same rate as in the IAEA high projection, and its share of global electricity generation reaches 22%. The other four IEA scenarios cluster around the level of the dotted white line, at about 5 650 TWh, or an average growth rate of 1.7% from 2005.

The WETO cases in 2050 use between 14 800 TWh (reference case - 25% share) and 21 400 TWh (hydrogen case - 37% share) of nuclear electricity: certainly an outlook that breaks with short-term trends and the cautious projections of the IEA and IAEA. The WETO cases assume

Figure 6-17 Electricity generation from nuclear power in the WETO-H_2 reference case
Source: European Commission



the implementation of drastic climate-change policies (carbon taxes, etc.) consistent with a definition of a 2°C increase in mean global temperature (or a maximum CO_2 concentration of 450 ppmv) as the normative limit for the avoidance of dangerous anthropogenic interference with the climate system. Other critical assumptions are accelerated innovation and technology learning, technology diffusion and adoption of Generation IV nuclear technologies and fuel cycles. Nuclear power would become a major supplier of both electricity and hydrogen.

The nuclear shares of the WETO cases are consistent, however, with many long-term business-as-usual scenarios that were developed for assessing greenhouse gas emission profiles in the absence of designated climate policies. Scenarios that extend to 2050 and beyond account for a changed overall energy resource situation, including depletion of low-cost fossil occurrences or the probability that the most convenient sites for renewables will have already been utilised. Fossil fuels extracted in 2050 will therefore come from higher cost-categories than the cheaper fossil fuels against which nuclear energy is competing in the shorter run. For example, the non-climate-intervention scenarios of the Intergovernmental Panel on Climate Change (IPCC) project between 15% and 26% nuclear electricity for the year 2050 (IPCC, 2000).

Concluding Remarks

Taken together, these new projections and scenarios present a picture with opportunities for significant nuclear expansion, but still with substantial uncertainty. A number of developments in 2006 suggest that the renewal of interest in nuclear power may reasonably soon lead to increases in construction. These include expansion plans announced in 2006 by Japan and the Russian Federation, as well as previously announced expansion plans of China, India, the Republic of Korea and Pakistan. They include the large number of intended Combined License applications that companies and consortia have announced in the USA, which altogether involved approximately 25 new reactors. They include two site-preparation applications in Canada and the UK White Paper's conclusion that new nuclear power stations could make a significant contribution to meeting the UK's energy policy goals. They include a joint feasibility study launched by utilities from Estonia, Lithuania and Latvia for a new nuclear power plant to serve all three countries, and the Belarus Government's approval of a working plan for construction of the country's first nuclear power plant to follow the expiration of a 10-year moratorium on nuclear construction. They include announcements made by Egypt, Indonesia, Nigeria, Poland, Turkey and Vietnam on the steps they are taking towards their first nuclear power plants. Finally, they include the explicit interest in nuclear power expressed by more than two dozen countries that currently do not operate nuclear power plants.

Whether and how quickly this interest ripens into a broader commitment to nuclear power will in large part depend on economics: on the affordability of nuclear power relative to alternatives, on the ability of next-generation nuclear technologies to cut capital costs, on the ability of nuclear power to deliver its services and benefits at reasonable costs and on creative fuel-cycle arrangements that allow countries to enjoy the benefits of nuclear power plants without the need to incur the costs of a nuclear infrastructure (take-back and leasing of nuclear fuel or nuclear batteries). It will also depend on government policies: environmental considerations driving or driven by the Kyoto Protocol, and supply-security considerations driving or driven by the need to strengthen the NPT. But most importantly, it will depend on the continued safe and economic operation of the current fleet of nuclear power plants around the world.

H-Holger Rogner
Alan McDonald
International Atomic Energy Agency (IAEA)

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TABLES

Table Notes

As far as possible, the data shown in Table 6-5 are as reported by WEC Member Committees in 2006/7. If information was not available from this source, data have been derived from the following published sources:

- *Nuclear Power Reactors in the World*; April 2006; International Atomic Energy Agency, Vienna;
- *Elecnuc: Les Centrales Nucléaires dans le Monde 2006*; Commissariat à l'énergie atomique, Paris.

Capacity data relate to the installed net generating capacity of nuclear power stations connected to the grid on 31 December 2005.

Table 6-5 Nuclear Energy: capacity and generation

	In operation in 2005		Under construction at end-2005		Net generation in 2005	Nuclear share of electricity generation in 2005
	Units	Capacity	Units	Capacity		
	(number)	(MW_e)	(number)	(MW_e)	(TWh)	(%)
South Africa	2	1 800			11.3	4.9
Total Africa	**2**	**1 800**			**11.3**	
Canada	18	12 500			87.0	15.0
Mexico	2	1 310			10.8	5.0
United States of America	104	99 988			782.0	19.3
Total North America	**124**	**113 798**			**879.8**	
Argentina	2	935	1	692	6.4	6.9
Brazil	2	1 901			9.9	2.5
Total South America	**4**	**2 836**	**1**	**692**	**16.3**	
Armenia	1	376			2.5	42.7
China	9	6 572	3	3 000	50.3	2.0
India	15	3 040	8	3 602	15.7	2.8
Japan	56	47 839	1	866	280.7	29.3
Korea (Republic)	20	16 810			139.3	44.7
Pakistan	2	425	1	300	2.4	2.8
Taiwan, China	6	4 904	2	2 600	38.4	17.7
Total Asia	**109**	**79 966**	**15**	**10 368**	**529.3**	
Belgium	7	5 801			45.3	55.6
Bulgaria	4	2 722	2	1 906	17.3	44.1
Czech Republic	6	3 368			23.3	30.5
Finland	4	2 696	1	1 600	22.3	32.9
France	59	63 363			430.0	78.3
Germany	17	20 303			154.6	31.0
Hungary	4	1 755			13.0	37.2
Lithuania	1	1 185			10.3	69.6
Netherlands	1	449			3.8	3.9
Romania	1	655	1	655	5.1	9.3
Russian Federation	31	21 743	4	3 775	137.3	15.8
Slovakia	6	2 460	2	820	16.3	56.1
Slovenia	1	656			5.6	42.4
Spain	9	7 588			54.7	19.6
Sweden	10	8 961			69.5	46.6
Switzerland	5	3 220			22.0	38.0
Ukraine	15	13 107	2	1 900	83.3	48.5

Table 6-5 Nuclear Energy: capacity and generation

	In operation in 2005		Under construction at end-2005		Net generation in 2005	Nuclear share of electricity generation in 2005
	Units	Capacity	Units	Capacity		
	(number)	(MW_e)	(number)	(MW_e)	(TWh)	(%)
United Kingdom	23	12 144			75.0	19.0
Total Europe	**204**	**172 176**	**12**	**10 656**	**1 188.7**	
Iran (Islamic Rep.)			1	915		
Total Middle East			**1**	**915**		
TOTAL WORLD	**443**	**370 576**	**29**	**22 631**	**2 625.4**	

Notes:

1. The capacity and output of the Krsko nuclear power plant, shown against Slovenia in the table, is shared 50/50 between Slovenia and Croatia
2. Japan includes the Monju FBR (246 MW_e net), which is being remodelled (see Country Notes) after being shut-down since December 1995

COUNTRY NOTES

The Country Notes on Nuclear have been compiled by the Editors, largely on the basis of material published in:

- *Nuclear Power Reactors in the World*, April 2006, International Atomic Energy Agency, Vienna;
- *Elecnuc: Les Centrales Nucléaires dans le Monde 2006*, Commissariat à l'énergie atomique, Paris;
- *WNA News Briefing,* World Nuclear Association, London;
- *WNN Newsletter*, World Nuclear Association, London;
- *WNN Overview*, World Nuclear Association, London;
- *WNN Weekly*, World Nuclear Association, London.

Information provided by WEC Member Committees has been incorporated when available.

Argentina

There are two NPPs: Atucha-I, a 335 MW_e PHWR supplied by Germany, and Embalse, a Canadian-designed 600 MW_e PHWR; Atucha-I came online in 1974, Embalse in 1983. In 2005 the two nuclear stations provided 6.9% of Argentina's electricity output.

The construction of a third unit (Atucha-II), a 692 MW_e PHWR, has been interrupted since 1995. The project had advanced 80%, and the estimated time to complete the work from the date it is restarted is 52 months. In August 2006 the Government announced a plan to extend the lives of the existing nuclear plants and to complete Atucha-II by 2010, with assistance from Canada. The Government also envisages the subsequent construction of a fourth reactor, to enter operation around 2015. Three months later Atomic Energy of Canada Ltd (AECL) was engaged by Nucleoelectrica Argentina SA to refurbish Embalse, to carry out a feasibility study for a 700 MW_e Candu 6 reactor to be built between 2010 and 2015, and to assist in the completion of Atucha-II.

Armenia

A NPP came into operation at Medzamor, 64 km from the capital Yerevan, in 1976 but it was closed down in 1989 following an earthquake the previous year. Concern over the station's safety from a seismic point of view was exacerbated by the repercussions of the Chernobyl incident.

One of the two original WWER units (Medzamor-2) has been upgraded and refurbished, coming back into commercial operation in 1996 with a capacity of 376 MW_e. It provided about 43% of Armenia's electricity output in 2005.

Armenia has faced international pressure, especially from its neighbour Turkey, to shut down Medzamor-2 on the grounds of safety. In May 2006 the Armenian Minister of Finance and Economy announced plans for the construction of a 1 000 MW_e nuclear plant to replace Medzamor-2. The Deputy Minister of Energy was reported in April 2007 as saying that Armenia needed a 1 000 MW_e unit built by 2016 and a second unit after 2020.

Australia

In November 2006 a draft report was issued by a government task-force set up to study the nuclear energy industry. The report was quoted as saying that 'nuclear power is the least-cost low-emission technology that can provide base-load power', and as predicting that Australia could have a nuclear power reactor in operation in as little as ten years – although 15 years would be more probable – and could potentially have up to 25 nuclear power reactors in operation by 2050, supplying one-third of the country's electricity.

Belarus

In July 2006 it was reported that the Government had approved a working plan for the construction of the republic's first NPP. The plan, which had been drafted by the National Academy of Sciences of Belarus, proposed a 2 000 MW_e plant, probably comprising two reactors. Towards the end of November the President of Belarus declared that the country had no alternative to developing its own nuclear energy and indicated that the proposed installation would be built in the southeastern region of Mogilev, and was planned to come into operation in 2015.

Belgium

A total of seven reactors were constructed between 1975 and 1985, four units at Doel and three at Tihange; they are all of the PWR type, with a current aggregate net generating capacity of 5 801 MW_e. In 2005, nuclear power provided about 56% of Belgium's electricity generation.

In January 2003, Belgium's Senate voted for a nuclear phase-out law which stipulates that all seven units shall be closed after completing 40 years of operation. The first reactors are thus due to be shut down in 2015, the last in 2025. However, the preliminary report of a study commissioned by the Federal Energy Ministry, released in November 2006, concludes that the substantial change in circumstances since the passing of the phase-out law 'requires a paradigm shift of the current official Belgian standpoint on nuclear power'.

Brazil

At the end of 2005, Brazil had two NPPs in operation: Angra-1, a 626 MWe net PWR, and Angra-2 (1 275 MWe net). In an electricity market dominated by hydropower, nuclear's share of generation in 2005 was only 2.5%.

A project for completing the construction of a third unit at Angra, of similar size to Angra-2, is under discussion in the Ministry of Mines and Energy (MME), which is responsible for the definition of energy policies. Many aspects are being analysed, including the project's environmental and economic viability. Work on the site had been started in 1983, but was suspended after about three years.

According to the *Ten-Year Plan for the Expansion of Electrical Energy 2006-2015*, published by MME, Angra-3 is now scheduled to come on stream in December 2012.

Bulgaria

Six WWER units have been constructed at Kozloduy, in the north-west of the country, close to the border with Romania. Four units (each of 408 MW_e net capacity) were brought into operation between 1974 and 1982, and two others (each of 953 MW_e capacity) were commissioned in 1987 and 1989, respectively. The combined output of the Kozloduy reactors provided 44% of Bulgaria's electricity generation in 2005.

Kozloduy-1 and -2 were shut down in December 2002, followed by Kozloduy-3 and -4 at the end of 2006, in accordance with the terms of Bulgaria’s accession to the European Union.

In April 2005 the Government approved the construction of a second NPP, comprising two 1 000 MW_e gross (953 MW_e net) PWRs, to be sited at Belene which is, like Kozloduy, on the banks of the Danube, Bulgaria’s border with Romania. Work on this site had begun in 1987 but has been on hold since 1991. Belene-1 is scheduled for completion by 2011, Belene-2 by 2013. In October 2006 the Bulgarian electric utility NEK awarded a contract to Atomstroyexport of Russia (heading a consortium including AREVA NP, Siemens and a number of Russian and Bulgarian companies) for two third-generation WWER reactors at Belene.

The Bulgarian WEC Member Committee foresees a total nuclear capacity of 4 000 MW_e (3 812 MW_e net) at end-2020, with four units in operation.

In March 2007, five Balkan states (Bulgaria, Serbia, Macedonia (Republic), Albania and Croatia) called on the European Union to allow Bulgaria to restart Kozloduy-3 and -4, in order to alleviate electricity supply shortages in the region.

Canada

There are currently 20 nuclear power reactors in Canada that are operational or being refurbished for operation in the near future. These reactors are for the most part located in the province of Ontario, which houses 18 reactors: Bruce (8), Pickering (6) and Darlington (4). There is one reactor in Quebec (Gentilly) and another in New Brunswick (Point Lepreau). Of these 20 reactors, 18 are currently in full commercial operation. All Canadian nuclear power plants are of the Pressurised Heavy Water Reactor (PHWR) type, using the Candu design. Canada’s operational nuclear generation capacity is about 12.5 GW. In 2005, these facilities provided 87 TWh, equal to 15% of Canada’s total electrical generation.

Two nuclear reactors are laid-up at the Bruce A station. The first unit that is being refurbished, Bruce A1, is expected to be re-commissioned by 2009, while Bruce A2 should be re-commissioned in 2010. Once re-commissioned, these reactors will increase nuclear generating capacity by 1 540 MW.

In addition to the 20 reactors noted above, there are two reactors at Pickering that are closed, Pickering A2 and A3 (both rated at 515 MW). Currently, Ontario Power Generation (OPG), which owns the reactors, does not view restarting these reactors as an economically viable option. However, should conditions warrant it, OPG may proceed with their refurbishment.

The Ontario government and Ontario Power Generation are also considering building new nuclear generation facilities at the Darlington site. This process is currently in its early stages. A submission has been made to the Canadian Nuclear Safety Commission (CNSC) for a Site Preparation License.

The CNSC is an independent agency of the federal Government in charge of regulating the nuclear industry and nuclear materials. The federal Government also provides financial support for the research and development programme of Atomic Energy of Canada Limited (AECL).

In March 2007, Energy Alberta was reported to be planning for a two-unit Candu NPP to supply steam and electricity for oil sands extraction and processing. The units would come into operation in 2016 and 2017 and would probably be followed by two more.

China

China's first NPP, Qinshan 1, a 288 MW_e PWR, was connected to the grid in December 1991 and began commercial operation in April 1994. Eight more NPPs (six PWRs and two PHWRs) have subsequently been installed. At end-2005, China's nuclear generating capacity stood at 6 572 MW_e; with output from the nine units providing 2.0% of its electricity generation during the year.

Three more nuclear reactors (two 1 000 MW_e WWERs and one 1 000 MW_e PWR) were under construction at the end of 2005. One of the WWERs (Tianwan 1) was connected to the grid in May 2006; fuel loading at the other (Tianwan 2) began in March 2007.

In June 2005, the president of China National Nuclear Corporation was reported as stating that China intended to increase its nuclear generating capacity to 40 GW_e (4% of total installed capacity) within 15 years. Numerous schemes for new reactors have been put forward in recent years, some of which are currently passing through the licensing process.

China is interested in developing the pebble bed reactor and is planning to cooperate with South Africa in High Temperature Reactor (HTR) demonstration projects and commercialisation. Although both countries use the same pebble bed concept as the source of heat, their planned power conversion systems differ. China's first HTR plants will incorporate indirect-cycle steam turbine systems, while the South African versions will feature direct-cycle gas turbine systems.

Czech Republic

There are four reactors at Dukovany, which came into operation between 1985 and 1987. Currently, three have a net capacity of 412 MW_e whilst the fourth is rated at 427 MW_e. Two further units have been constructed: Temelin-1 came online in December 2000 (925 MW_e) and Temelin-2 during 2003 (780 MW_e at end-2005, 930 MW_e from February 2006). In 2005, nuclear provided 30% of net electricity generation.

The commissioning of Temelín-2 marked the completion of the Czech Republic's current nuclear programme. In January 2005, the state electrical utility CEZ was reported to be considering an extension of the operating life of the Dukovany units by 10 or possibly 20 years.

Egypt (Arab Republic)

The WEC Member Committee has reported that Egypt is studying the viability of constructing nuclear reactors for electricity generation and sea water desalination. The first nuclear power plant is expected to be operational by 2015.

In September 2006, Egypt's Energy Minister was reported as saying that a 1 000 MW_e NPP would be built at El-Dabaa, on the Mediterranean coast, within the next 10 years.

Finland

Four nuclear reactors were brought into operation between 1977 and 1980: two 488 MW_e WWERs at Loviisa, east of Helsinki, and two 840 MW_e BWRs at Olkiluoto. In 2005 the four units accounted for virtually a third of Finland's electricity output.

An application for a Decision-in-Principle (DiP) on a fifth NPP unit was filed in November 2000 by the nuclear power company Teollisuuden Voima (TVO). In May 2002 the Finnish Parliament ratified the Government's earlier favourable DiP and TVO was then authorised to continue preparations for the construction of a new NPP.

In October 2003, TVO announced that its preferred site for the fifth nuclear station was at Olkiluoto, 250 km north-west of Helsinki. A construction contract was signed with a consortium of Framatome (now AREVA NP) and Siemens in December of the same year. In January 2004 TVO submitted its construction licence application for the OL3 reactor unit on the Olkiluoto NPP site in the municipality of Eurajoki. In February 2005, the Government granted the licence for constructing the OL3 unit. The new nuclear power unit of 1 600 MW_e (net) is expected to be in commercial use in 2010.

The current operating licences of Loviisa 1 & 2 and Olkiluoto 1 & 2 are valid up to the end of 2007 and 2018, respectively. For the Loviisa units the operating licence renewal application was submitted to the authorities for regulatory review in autumn 2006. For the Olkiluoto units the utility must submit to the Finnish Radiation and Nuclear Safety Authority (STUK) by the end of 2008 a comprehensive periodic safety review report, after which STUK will make its own safety assessment.

In April 2007 Fortum and TVO, the owners of the Finnish NPPs, were embarking on environmental impact assessments for new nuclear power units at the Loviisa and Olkiluoto sites respectively, preparatory to possible applications to construct new plants. In a separate development, the German utility E.ON was reported to be purchasing land for a possible NPP site in the vicinity of Loviisa.

After the start of commercial operation, all Finnish reactor units have continuously had very high annual load factors. The production-weighted average load factor has been above or very close to 90% since 1983. Besides success in efforts to maintain high reliability of key operational and safety systems, the short refuelling and maintenance shutdowns have significantly contributed to the high performance figures.

France

France has pursued a vigorous policy of nuclear power development since the mid-1970s and now has by far the largest nuclear generating capacity of any country in Europe, and is second only to the USA in the world. At end-2005 there were 59 reactors in operation, with an aggregate net capacity of over 63 000 MW_e. NPPs provide some 78% of France's electricity output. Apart from a single fast reactor (Phenix), PWRs account for the whole of current nuclear capacity.

Electricité de France (EDF) announced in October 2005 that it was planning to increase the generating capacity of five reactors at three of its nuclear power plants in 2008-2010 by replacing turbine rotors, thus adding some 30 MW_e to each unit’s capacity.

On 5 May 2006 EDF applied to the Ministry of Industry and the Ministry of Environment for authorisation to construct and operate Flamanville-3, its first European Pressurised Water Reactor (EPR), which is scheduled for completion in 2012. Subsequently, contracts have been awarded by EDF for the major aspects of the project, on which construction work is expected to start by the end of 2007.

In December 2006, the French Government’s Atomic Energy Committee announced a plan to construct a sodium-cooled fast reactor by 2020, with the final decision whether to go ahead being made in 2012. A design for a gas-cooled fast reactor will also be developed concurrently. These fourth-generation models are envisaged as entering commercial service after 2035-2040.

Germany

A total of 17 reactor units, with an aggregate net generating capacity of 20 303 MW_e, were operational at the end of 2005. Nuclear power provided 31% of Germany's net electricity generation in that year.

In June 2000, the Federal Government concluded an agreement with the German utility companies that provides for an eventual phasing-out of nuclear generation. The agreement specifies a maximum of 2 623 TWh for the lifetime production of all existing nuclear reactors, which implies an average plant lifetime of 32 years. As the newest German reactor (Neckarwestheim-2) was connected to the grid in January 1989, it could be expected to survive until 2021; however, utilities will be allowed to switch productive capacity between stations, so that the life of the newer, more economic plants could be extended by prematurely shutting down other units. Moreover, the calculated 32-year average lifespan is predicated on a capacity factor of over 90%; using a somewhat lower (and more realistic) level of, say, 85% the average plant lifetime would approach 35 years.

Germany's pioneer PWR, the 340 MW_e (net) unit at Obrigheim, was shut down on 11 May 2005 under the terms of the 2000 nuclear phase-out agreement, after 36 years of successful operation. The next reactor due for closure under the phase-out plan is Biblis A, which came into service in 1975 and is scheduled for shutdown in February 2007.

In October 2006, the German Chancellor Angela Merkel was reported as saying that it was a mistake for the country to shut down all its nuclear plants over the ensuing 14 years, even though her coalition government was committed to the plan.

Hungary

Four WWER reactors, with a current aggregate capacity of 1 755 MW_e, came into commercial operation at Paks in central Hungary, between 1983 and 1987. Their combined output in 2005 accounted for about 37% of total net electrical generation.

The Hungarian WEC Member Committee reports that in 2005 the Hungarian Parliament took note of a resolution on extending the lifetime of the Paks units. The resolution declares that nuclear is a safe, long-term solution to meeting the country's electricity needs.

In 2005 the Hungarian Energy Authority issued a licence for upgrading the nominal power of all four units by about 8%. It is planned to realise this upgrading step by step.

India

At the end of 2005, India had 15 reactor units in operation, with an aggregate net generating capacity of 3 040 MW_e. Thirteen were PHWRs, the other two being of the BWR type: most were relatively small units, with individual capacities up to 202 MW_e; the exception is Tarapur-4, with a net capacity of 490 MW_e. Output from India's nuclear plants represented 2.8% of total electricity generation in 2005. Tarapur-3, a second 490 MW_e PHWR, commenced commercial operation in August 2006.

Four 202 MW_e PHWRs were under construction at end-2006: Kaiga-3 and -4 and Rajasthan-5 and -6; as well as two 917 MW_e WWERs (Kudankulam 1 and 2) and a 470 MW_e fast breeder reactor (PFBR). In all, these seven units will add over 3 000 MW_e to India's nuclear generating capacity. Kaiga-3 was connected to the grid in April 2007, Kaiga-4 is scheduled to enter operation by the end of 2007.

Cabinet approval was granted in September 2005 for the construction of eight new reactors at four sites: two 600 MW_e heavy water reactors at Kakrapar (Gujarat state); two 700 MW_e heavy water reactors at Rawatbhata (Rajasthan); two 1 000 MW_e light water reactors at Kudankulam (Tamil Nadu) and two more light water reactors at Jaitapur (Maharashta).

In April 2006, the Indian President, Dr A.P.J. Abdul Kalam, proposed that the Government should aim to raise the republic’s nuclear generating capacity from the presently planned 2020 level of 24 000 MW_e to 50 000 MW_e by 2030.

Dr. Kalam also expressed his belief in the need for India to develop thorium-fuelled reactors. In this connection, it was reported in January 2007 that construction of India’s first advanced heavy water reactor (AHWR), using a thorium fuel cycle, would begin during the year, subject to a pre-licensing review currently being undertaken by the Atomic Energy Regulatory Board. The location of the proposed 300 MW_e AHWR has not yet been announced. India has substantial reserves of thorium, which are much larger than its known uranium resources.

The state-owned National Thermal Power Corporation (NTPC) was reported in August 2006 to be bringing forward plans for a large (2 000 MW_e) NPP, with its completion now envisaged for 2013-2014 rather than the previously-scheduled 2017.

Indonesia

The Minister of Research and Technology announced plans in January 2003 for the construction of Indonesia's first NPP. In September 2006, it was reported that before the end of the year the Government would select an agency to be responsible for implementing a project to construct two 1 000 MW_e nuclear power reactors by 2016. These will be built on one of three sites in north central Java. Later in 2006, the Minister of Energy and Mineral Resources stated that construction of the first unit was scheduled to begin in 2010, with a view to its becoming operational in 2017. Indonesia plans for nuclear energy to contribute some 4 000 MW_e to its electricity generating capacity by 2025.

Iran (Islamic Republic)

Construction of two 1 200 MW_e PWRs started at Bushehr in the mid-1970s, but work was suspended following the 1979 revolution. In April 2006, the IAEA reported that Iran had one unit under construction: Bushehr-1 (1 000 MW_e gross, 915 MW_e net). Iran signed an agreement with Russia in September 2006 for the supply of nuclear fuel assemblies in the following March, with a view to Bushehr-1 reaching initial criticality in September 2007 and grid connection some two months later. By end-April 2007, the completion schedule for the plant had been extended for an unspecified period, on account of a financial dispute with the Russian contractor AtomStroyExport.

Iran announced an international tender in April 2007 for the design and construction of two light-water reactors, each of up to 1 600 MW_e, for installation near Bushehr.

Japan

At the end of 2005 there were 55 operable nuclear reactors, with an aggregate generating capacity of 49 580 MW_e gross, 47 593 MW_e net. Within this total there were 28 BWRs (24 764 MW_e gross, 23 909 MW_e net), 23 PWRs (19 366 MW_e gross, 18 425 MW_e net) and four ABWRs (5 450 MW_e gross, 5 259 MW_e net). In 2005, the output from Japan's NPPs provided about 29% of its net generation of electricity.

Since 2004 three reactors have come into commercial operation: Hamaoka-5 (1 380 MW_e ABWR) in January 2005, Higashidori-1 (Tohoku) (1 100 MW_e BWR) in December 2005 and Shika-2 (1 358 MW_e ABWR) in March 2006.

Including two reactors on which construction work has recently started – Shimane-3 and Ohma – work on eight reactors is planned to commence during the period to 2012; six of these will be ABWRs, the other two (Tsuruga-3 and -4) will be APWRs.

The Japanese WEC Member Committee expects that by the end of 2020 there will be 68 nuclear reactors in operation, with a total gross capacity of 66 810 MW_e (approximately 64 000 MW_e net).

The Institute of Energy Economics, Japan was reported in April 2006 as forecasting that nuclear generating capacity in Japan would rise to 62 860 MW in 2030, with nuclear's share of total electricity generation some 41% in that year as against 29% in 2005, and nuclear's share of primary energy increasing from 11% in 2004 to 20% in 2030. Existing reactors were expected to operate for 60 years, with improvements incorporated during their lifetime. Only one reactor (the 341 MW_e Tsuruga-1) was expected to be shut down before 2030. The Institute expected positive steps to be taken to raise the capacity factors of Japanese reactors, which have tended to be lower than those achieved in North America and Europe, to an average of around 88% by the end of the period.

The Monju prototype fast-breeder reactor (246 MW_e net) has not yet been put back into operation, more than eleven years after a serious leak of sodium caused it to be shut down. In February 2006, the governor of Fukui prefecture approved the remodelling of the reactor. Preparatory work was started straightaway, with the task of remodelling expected to take some 17 months. Once the work has been completed, it will be necessary to obtain further consents from Fukui prefecture and the city of Tsuruga before the unit can be restarted. Three months later the Supreme Court overruled an earlier decision by a lower court and approved Government plans to restart

Monju after modifications. Actual modification work began on 1 September; the reactor is scheduled to reach initial criticality in February 2008.

Kazakhstan

The only NPP to have operated in Kazakhstan was BN-350, a 70 MW_e fast breeder reactor located at Aktau on the Mangyshlak Peninsula in the Caspian Sea. It came into service in 1973 and was eventually shut down in June 1999. Reflecting its small generating capacity, and its additional use for desalination and the provision of process heat, BN-350's contribution to the republic's electricity supply was minimal: over its lifetime of operation, its average annual output was only about 70 GWh.

In July 2006, it was reported that Russia and Kazakhstan had agreed to establish a joint venture for the design of next-generation small and medium power reactors and for the construction of a small NPP in Kazakhstan.

Korea (Democratic People's Republic)

A project for the construction of a 1 040 MW_e PWR was initiated in 1994 by the Korean Peninsula Energy Development Organisation (KEDO), funded by the USA, the Republic of Korea, Japan and the EU. It was suspended in 2002 and finally abandoned in June 2006.

Korea (Republic)

At end-2005, there were 20 nuclear reactors (16 PWRs and 4 PHWRs) in operation, with an aggregate net capacity of 16 810 MW_e. Two PWRs (Ulchin-5 and -6) with a total capacity of 1 920 MW_e, began commercial operations in November 2004 and August 2005, respectively. Nuclear power makes a substantial contribution to Korea's energy supply, providing nearly 45% of its electricity in 2005.

Six more reactors are planned to be built during the next seven years, with completion dates between 2010 and 2014. Construction of the 960 MW_e Shin Kori-1 and -2 PWRs was accorded final approval by the Ministry of Science and Technology on 30 June 2005; these units are planned to come into service in 2010 and 2011, respectively.

Work on Shin Wolsong-1 and -2 (also known as Wolsong-5 and -6) got under way in 2006 - they are scheduled to come into operation in 2011 and 2012. Contracts were awarded in August 2006 for the construction of two APR-1400 reactors at the Shin Kori site (Shin Kori-3 and -4), with completion planned for 2013 and 2014.

Lithuania

Two LWGRs (each of 1 500 MW_e gross capacity) were built at Ignalina, north-east of Vilnius, in the mid-1980s: one was commissioned in December 1983 and the other in August 1987. After the accident at Chernobyl, the capacity of the Ignalina NPP was derated to 2 600 MW_e gross (2 370 MW_e net) for safety reasons. Ignalina-1 was shut down on 31 December 2004, in accordance with the terms of Lithuania's accession to the European Union. In

2005, Ignalina-2 accounted for nearly 70% of the republic's electricity generation.

The National Energy Strategy approved by the Seimas (parliament) in 2002 provides for closure of Unit 2 of Ignalina NPP in 2009. In the draft Strategy updated in 2006 it is declared that within the period 2015-2017 a new nuclear power plant will be commissioned. It is assumed that this power plant will satisfy much of the electricity requirements of the three Baltic States and will increase energy security in the region.

The three Baltic States signed an agreement in February 2006 to build a new NPP in Lithuania by 2015. It was envisaged that the respective state-owned energy companies would take equal shares in the project. A feasibility study conducted by the three power companies (October 2006) confirmed the need for new capacity and identified a number of advantages in opting for the nuclear route. In December 2006 it was reported that Poland had expressed an interest in taking a 25% share in the NPP project, alongside an agreement to construct a 400 kV transmission line linking the Polish and Lithuanian electricity grids. Two months later, all four parties reached an agreement in principle to build an NPP on the Ignalina site by 2015. Lithuania would take a 34% share of the project, with Latvia, Estonia and Poland each having a 22% share.

Mexico

There is a single nuclear power station with two BWR units of total net capacity 1 310 MW_e, located at Laguna Verde in the eastern state of Veracruz. The first unit was brought into operation in April 1989 and the second in November 1994. Laguna Verde's electricity output accounted for 5% of Mexico's total net generation in 2005.

In its submission for the present *Survey*, the Mexican WEC Member Committee reported that while there were no definite plans to expand the use of nuclear energy, upgrading the existing units had been openly discussed in order to increase their output by around 10%. Several officials, including the Energy Secretary and the president of the national utility, had publicly called for an open discussion to re-initiate the nuclear power programme.

In March 2005, the Comisión Federal de Electricidad (CFE) was reported to be considering the construction of some 10 000 MW_e of new nuclear capacity. The possible expansion of nuclear power capacity could include additional units at Laguna Verde as well as installations at two new sites.

A year later, the CFE Director-General announced that the commission aimed to construct a new NPP by 2020 at the latest, to help meet rising electricity demand. He also stated that CFE was spending $ 150 million on raising the capacity of the two Laguna Verde reactors. A major retrofit project for Laguna Verde was announced in March 2007; when completed in 2010, the capacity of each unit will have been increased by 20% to about 785 MW_e.

Netherlands

Two NPPs have been constructed in the Netherlands: a 55 MW_e BWR at Dodewaard (which operated from 1968 to 1997) and a 449 MW_e PWR at Borssele (online from 1973). Borssele's output accounted for almost 4% of Dutch electricity generation in 2005.

In January 2006 the Dutch Government agreed to a 20-year life extension for the Borssele plant, allowing it to operate until December 2033; six months later Parliament ratified the decision. Also in June 2006 , the chairman and CEO of Delta, one of the companies with shareholdings in Borssele's operator EPZ, revealed that Delta was investigating the possibility of constructing a new reactor at Borssele, which could be operating by 2016. A major refit completed at the end of 2006 resulted in Borssele's capacity being raised to 485 MW_e.

September 2006 saw a reversal of the Government's phase-out policy, when new conditions for the construction of NPPs were announced. Any new reactor must be a third-generation model, with barriers to prevent containment breaches. Other rules relate to the disposal of high-level waste and used fuel, plant dismantling and decommissioning funds.

Pakistan

A small (125 MW_e) PHWR plant was commissioned in 1971. Known as Kanupp (Karachi Nuclear Power Plant), this facility has made a minor contribution (less than 1%) to the national annual electricity supply. In June 2000, it was joined by a second plant (Chasnupp 1), a 300 MW_e PWR constructed at Chasma. Together, the two plants contributed 2.8% to Pakistan's power supplies in 2005.

A third NPP (Chasnupp-2, or C-2), with a net capacity of 300 MW_e, has (with assistance from China) been under construction since December 2005: completion is due in 2011.

In August 2005, the Atomic Energy Commission (PAEC) was reported to be planning to seek assistance from the USA and the EU for the construction of 13 new nuclear reactors, with an aggregate capacity of 8 400 MW_e. PAEC was said to be proposing that the new reactors would be either fully owned by the western countries that built them or jointly-owned with Pakistan under IAEA supervision. At the beginning of 2006, Pakistan was reported to be negotiating with China to buy six to eight 600 MW_e nuclear reactors, with construction starting by 2015 and completion by 2025. However, a later report (October 2006) referred to a programme for six Chinese-designed 300 MW_e units, for which sites had been selected.

Romania

Romania's first nuclear plant - a PHWR supplied by AECL of Canada, with a current net capacity of 655 MW_e - came online in 1996 at Cernavoda in the east of the republic. In 2005, it supplied 9.3% of Romania's electricity generation.

The Romanian WEC Member Committee reports that the Cernavoda NPP was designed for five reactors, using Canadian Candu-type technology. Currently the power plant has one functional reactor; a second reactor is scheduled to be commercially viable in the summer of 2007, thus increasing Cernavoda's output to 18% of national electricity production. Nuclear fuel loading at Cernavoda 2 began in February 2007, preparatory to the unit coming into operation in September 2007.

As a result of a feasibility study carried out by Nuclearelectrica SA (the operator of Cernavoda 1 & 2), the Ministry of Economy and Commerce (MEC) will propose to the Government the simultaneous construction of the third and fourth reactors at the Cernavoda nuclear plant. The financial effort requires a 2.2 billion Euro investment. Work on Units 3 and 4 is planned to restart at the beginning of 2008, with completion taking some 64 months.

Russian Federation

There were 31 nuclear units installed at ten different sites at the end of 2005, with an aggregate net generating capacity of 21 743 MW_e. The reactor types represented consisted of eleven 925 MW_e LWGRs, nine 950 MW_e WWERs, four 411 MW_e WWERs, four 11 MW_e LWGRs, two 385 MW_e WWERs and one 560 MW_e FBR. In all, NPPs provided almost 16% of the Russian Federation's electricity output in 2005.

Four reactor units, with an aggregate capacity of 3 775 MW_e, were under construction at the end of 2005, comprising three 950 MW_e WWERs and one 925 MW_e LWGR (Kursk-5). Of the WWERs, Volgodonsk-2 (also known as Rostov-2) is due for completion in 2009, whilst Balakovo-5 and Kalinin-4 are expected to come online in 2010-2011.

In October 2006, it was reported that the Russian Government had formally adopted a two-stage development programme for nuclear energy, which includes plans for commissioning a new series of power reactors, to be implemented in two stages (2007-2010 and 2011-2015). The programme envisages that from 2009 Russia will add some 2 000 MW_e to its nuclear generating capacity each year, so that by 2015 ten new reactors should be in operation and a further ten under construction.

According to the head of the Federal Atomic Energy Agency (Rosatom), as reported in November 2006, the Federation plans to install 42 new nuclear reactors by 2030. It was reported in February 2007 that construction would commence (later in 2007) of Russia's first two advanced pressurised water reactors (AES-2006) of 1 200 MW_e each, with completion envisaged for end-2012.

Russia is building the world's first floating nuclear power plant at Severodvinsk on the White Sea, with completion scheduled for 2010. The pilot BNPP (buoyant nuclear power plant) will be assembled in a shipyard and then towed to the generating site. The vessel will be 140 m long and 30 m broad, with a displacement of 21 000 tonnes. It will accommodate two 35 MW_e reactors of a type similar to those on a nuclear icebreaker. The plant is designed to have a lifetime of 40-50 years. There are plans for two other BNPPs, to be sited at Vilyuchinsk and Pevek Bay, both in the far east of the Federation.

Slovakia

Four 408 MW_e WWERs were brought into service at Bohunice between 1978 and 1985; a slightly smaller (388 MW_e net) WWER came into operation at Mochovce in 1998. Mochovce-2 (also 388 MW_e) was connected to the grid just before the end of 1999 and went commercial in April 2000. Together, these six reactors are reported to have a current net capacity of 2 460 MW_e and to have provided 56.1% of the republic's electricity output in 2005.

The Bohunice-1 reactor (408 MW_e) was shut down on 31 December 2006, in accordance with the terms of Slovakia's accession to the European Union on 1 May 2004. Bohunice-2 is due for closure by the end of 2008.

According to a press report in August 2006, ENEL of Italy, which holds a 66% stake in the electric utility Slovenske Elektrarne (SE), will decide during the first half of 2007 whether to complete the construction of Mochovce-3 and -4 (2 x 405 MW_e), on which work was halted in the 1990s on account of a lack of financing.

In March 2007 it was reported that the German utility E.ON was considering constructing an NPP at the Bohunice site, in response to the Slovak Government's desire to maximise the utilisation of the infrastructure at Bohunice and to build a significant new power source there.

Slovenia

A bi-national PWR (current capacity 656 MW_e net) has been in operation at Krsko, near the border with Croatia, since 1981. Krsko's output, which is shared 50/50 with Croatia, accounted for 42% of Slovenia's net electricity generation in 2005. According to the Slovenian WEC Member Committee, Krsko will operate till 2023, with possible extension.

It was reported in June 2006 that the Slovenian Ministry of Energy was considering the construction of a second unit at Krsko. Further details emerged in October 2006, when the Economics Minister stated that the new reactor would probably be a PWR, with a net installed capacity of 1 000 MW_e; construction could begin in 2013, with commercial operation from 2017.

South Africa

There is a single nuclear power station at Koeberg, about 40 km north of Cape Town. The plant has two 900 MW_e PWR units which were commissioned in 1984-1985. The plant, which is owned and operated by Eskom, the national utility, provided just under 5% of South Africa's electricity in 2005.

Reflecting Eskom's recent involvement with the Global Roundtable on Climate Change and the 3C (Combat Climate Change) initiatives, the company is actively working towards diversifying its energy mix. Whilst coal-based electricity generation will continue to play a major role, the South African Minister for Public Enterprises announced in February 2007 that Eskom intended to build a second nuclear power station – a key component in the drive to reduce emissions.

Development of the pebble bed modular reactor (PBMR) continues. The PBMR concept envisages a number of small reactors operating in tandem. The current schedule is to start construction of a 165 MW_e demonstration plant at Koeberg in 2009 and for the first fuel to be loaded four years later. Construction of the first commercial PBMR modules is planned to start three years after the first fuel has been loaded into the demonstration reactor.

In March 2007 it was reported by *World Nuclear News* that PBMR Pty, the South African company developing the pebble bed concept, had discussed with Sasol the possibility of employing the PBMR in the production of synthetic fuels. Another possible application being considered is as a source of energy for oil sands extraction.

Spain

Nine nuclear reactors were brought into commission between 1968 and 1988: at the end of 2005, they had an aggregate net capacity of 7 588 MW_e and in 2005 provided 19.6% of Spain's electricity generation. Two of the units are BWRs (total capacity 1 510 MW_e), the rest being PWRs.

José Cabrera-1 (Zorita-1), Spain's oldest NPP (142 MW_e), was permanently shut down on 30 April 2006 after 38 years of operation. It had previously been scheduled for closure in 2008, but in 2004 the Government decided to close it two years earlier.

The Spanish WEC Member Committee states that, until recently, nuclear power policy in Spain has been based on the non-entrance of new units, relying instead on repowering some units and decommissioning old plants. Recent government announcements indicate a continuation of this policy. An important part of the energy programme will be the gradual substitution of nuclear plants by other energy sources, mainly renewables, in order to reach Spain's commitments under the Kyoto Protocol.

The Member Committee also reports that, on the other hand, the Ministerio de Industria Turismo y Comercio has opened a Debate Forum dealing with the future of nuclear energy in Spain. This Forum opens the door (or at least does not close it) for long-term development, although the Member Committee considers that it would be highly speculative to make any projection on this basis.

Sweden

Between 1971 and 1985 a total of 12 nuclear reactors (nine BWRs and three PWRs) commenced operation. The 10 units remaining in service at end-2005 had an aggregate net capacity of 8 961 MW_e. Nuclear power provided 46.6% of Sweden's net output of electricity in 2005.

In June 1997, the Swedish Parliament took a decision to start the phasing-out of nuclear power. The decision specified that the two units, 600 MW_e each, at the Barsebäck nuclear station were to be closed by end-June 1998 and end-June 2001, respectively; an earlier decision with regard to a final date for total nuclear phase-out by 2010 was explicitly removed, without specifying an alternative final date.

The execution of the first closure was delayed by legal conflicts between the owner, Sydkraft, and the Government. During November 1999 an agreement was reached concerning the level of compensation, and Barsebäck-1 was permanently taken out of operation at the end of the month, without the closure being enforced by law. The Barsebäck-2 reactor was shut down on 31 May 2005.

Sweden's nuclear capacity at end-2020 is forecast by the WEC Member Committee to total 10 400 MW_e from 10 units, implying that an overall increase of some 1 440 MW_e (or 16.1%) is obtained as a result of the uprating of existing reactors during the period 2006-2020.

Power uprates totalling 200 MW_e for the Ringhals-1 and -3 reactors were accorded government approval in October 2005. In June 2006, sanction was also given for a 250 MW_e increase in the capacity of the Oskarshamn reactor, to be carried out during 2008. Plans have also been announced for an uprate of the capacity of Forsmark’s three reactors by 410 MW_e between 2009 and 2011.

In October 2006, Sweden’s new Prime Minister, Fredrik Reinfeldt, stated that no political decision would be taken on phasing out nuclear power before 2010 and that renewed operating licences would not be issued for the Barsebäck reactors. He said that no construction of new reactors would be started before 2010, although the Government would consider applications to uprate existing nuclear capacity.

Switzerland

There are three PWRs and two BWRs in operation, with a total net generating capacity of 3 220 MW_e. All five reactors were commissioned between 1969 and 1984. Their output in 2005 accounted for 38% of Switzerland's total power generation.

In May 2003, two popular initiatives – one to extend a moratorium on the construction of nuclear plants that had lapsed in 2000, the other to phase out nuclear plants altogether – were rejected by majorities of 58.4% and 66.3%, respectively. A new Nuclear Energy Law (NEL) came into force in February 2005, along with a new main Nuclear Energy Ordinance (NEO). The NEL keeps the nuclear option open, addresses key issues relating to radioactive waste management and clearly empowers the Federal Council to authorise construction, operation and decommissioning of nuclear installations. Controversies on reprocessing were circumvented by a temporary ban (until 2016) on exports of spent nuclear fuels.

Decommissioning of the three oldest nuclear power plants, Beznau I and II and Mühleberg, with a combined capacity of 1 085 MW_e (one-third of the country’s total nuclear capacity) is expected around 2020. Furthermore, drawing rights for some 2 500 MW_e of French nuclear capacity will have to be renewed. Replacement of this capacity will be one of the major challenges for Swiss energy policy in the coming years, which has prompted a review of long-term energy perspectives. In presenting a new energy policy on 21 February 2007, the Federal Energy Minister announced that the Cabinet had decided that the existing five reactors should in due course be replaced by new nuclear plants.

Taiwan, China

There are six reactors in service at three locations (Chinshan, Kuosheng and Maanshan), with an aggregate net generating capacity of 4 904 MW_e; the four BWRs and two PWRs were all brought online between 1977 and 1985. In 2005 nuclear plants provided 17.7% of Taiwan's electricity generation (including cogeneration output).

Two more BWRs, with a total net capacity of 2 600 MW_e, are under construction at a fourth location (Lungmen). Owing to the intense political controversy generated by this project, its progress and eventual completion date remain subject to uncertainty. In August 2006, additional government funding was granted to Taipower for the completion of the Lungmen NPP. The first 1 300 MW_e ABWR unit may now commence operation in 2009, some three years behind schedule, while Lungmen-2 might be completed about a year later.

Turkey

The Turkish WEC Member Committee reports that there are currently no nuclear power plants in operation or under construction. In November 2004, the Turkish Electricity Transmission Company (TEIAS) prepared a report entitled *Electricity Energy Generation Planning Study for Turkey (2005-2020)*. This report is providing guidance for the decision–makers, investors and market actors on the timing, composition and capacities of the additional electricity generation sources needed for the next 15 year period. According to this planning study, it is planned to add about 4 500 MW_e total nuclear capacity by 2015, in the context of a high demand scenario (i.e. 7.9% increase per year).

In April 2006 the president of the Turkish Atomic Energy Agency announced that the country's first nuclear power plant would be located in the Black Sea province of Sinop. It is planned to start by installing a 100 MW_e prototype reactor at a new technological centre in Sinop, and then to construct a series of NPPs with an aggregate capacity of about 5 000 MW_e. The first reactor would come into service around 2012. The Prime Minister stated in June 2006 that Turkey planned to construct three NPPs by 2015.

Ukraine

At end-2005 there were 15 nuclear reactors (with a total net generating capacity of 13 107 MW_e) in service at four sites: they had come into operation between 1980 and 1995. Nuclear plants accounted for 48.5% of Ukraine's power output in 2005.

Four 925 MW_e RBMK reactors were installed at Chernobyl between 1977 and 1983. In April 1986 the last unit to be completed, Chernobyl-4, was destroyed in the world's worst nuclear accident. Chernobyl-2 was closed down in 1991, Chernobyl-1 in 1996 and Chernobyl-3 in December 2000.

The European Bank for Reconstruction and Development granted a loan to Ukraine to finance the completion in 2004 of two 950 MW_e (net) nuclear reactors (Khmelnitski-2 and Rovno-4), to replace the electricity output lost as a result of the shutdown of Chernobyl-3. Two further 950 MW_e WWERs (Khmelnitski-3 and -4) are partly built, with grid connection foreseen for 2015-2016.

In June 2005, the president of Energoatom stated that Ukraine planned to build a number of NPPs, with capacities in the 1 000-1 500 MW_e range, starting in 2008. Total baseload nuclear capacity is planned to grow to 20 000 MW_e (presumably gross, equivalent to 19 000 MW_e net) in 2030, with nuclear's share of electricity generation staying in the region of 45%. The Minister of Fuel and Energy was quoted as saying that the first two reactors would be commissioned by 2015 and that four more would follow by 2020.

In mid-2006, Energoatom invited bids to undertake a feasibility study for completing the Khmelnitski-3 and -4 reactors, which in 2005 had received government approval for completion.

United Kingdom

The UK had 23 nuclear reactor units in service at the end of 2005, with an aggregate net generating capacity of 12 144 MW_e. In 2005, nuclear power accounted for 19% of net electricity generation. Four Magnox reactors (Sizewell A-1 and -2 and Dungeness A-1 and -2) were shut down at the end of 2006, after operating for about forty years. Only two of the first generation of British nuclear power plants (Oldbury and Wylfa) are still in operation: these are scheduled to be shut down in 2008 and 2010, respectively. No new plants are under construction or on order.

The Department of Trade and Industry's 2006 Energy Review Report, *The Energy Challenge*, stated that 'the Government believes that nuclear has a role to play in the future UK generating mix'. Any new nuclear power station would be proposed, developed, constructed and operated by the private sector. Although there would be no subsidies, assistance would be forthcoming through streamlined planning procedures, pre-licensing, etc.

The White Paper, *Meeting the Energy Challenge*, published in May 2007, states that the Government's 'preliminary view' was that 'it is in the public interest to allow the private sector the option of investing in new nuclear power stations'. In mid-2007 a period of consultation began during which the Government will seek the views of the public and other interested parties before any firm decisions are made.

United States of America

At the end of 2005, there were 104 nuclear reactor units connected to the grid, with an aggregate net generating capacity of 99 988 MW_e (equivalent to about 27% of total world nuclear capacity). The totals include Brown's Ferry-1 (1 065 MW_e), which has been shutdown since March 1985 but is still fully licensed to operate. Nuclear plants accounted for 19.3% of US electricity output in 2005.

The US WEC Member Committee reports that national energy policy presently favours the construction of new nuclear plants. The US Department of Energy program *Nuclear Power 2010* (NP2010) is designed to encourage the initiation of new nuclear power construction by 2010. Programs under NP2010 include co-funding of the initial construction licensing cost for two nuclear reactors, including some first-of-a-kind engineering expenses. The Energy Policy Act of 2005 also provided incentives for initial nuclear power, including production tax credits, loan guarantees, and ‘standby' protection to cover some regulatory delays. Licensing procedures at the Nuclear Regulatory Commission have also been modified to facilitate the process of licensing and to limit the opportunities for intervention after construction has been licensed.

Recent times have witnessed a number of applications for nuclear construction licences and a spate of applications for the renewal of operating licences for existing reactors and, in many cases, for extensions of such licences by up to 20 years. By March 2007, the total number of licence renewals granted for US reactors stood at 48.

In a novel link between the nuclear industry and the renewables sector, a proposed new NPP near Bruneau, Idaho, envisages the co-generation of ethanol based on the supply of surplus heat from the NPP to a plant processing locally-produced grain.

Vietnam

A pre-feasibility study for nuclear power development was completed in early 2005 by an exploratory committee set up by the Government in 2001. The study envisages the construction of a 2 000 MW_e NPP in either Ninh Phouc or Ninh Hai, both situated in Ninh Thuan province, with anticipated completion during the period 2017-2020.

In May 2006 the chairman of the Vietnamese Atomic Energy Commission (VAEC) was reported as saying that a feasibility study for the NPP project would be completed in 2008. He indicated that if the project received approval, VAEC would organise construction to begin around 2011, with a view to completing the project by 2017. He added that the feasibility study had been ordered by the Ministry of Industry in anticipation of Vietnam's readiness to construct two to four reactors of 2 000-4 000 MW_e by 2020.

7. Hydropower

COMMENTARY

COMMENTARY

Introduction

The Chairman's Summary of the Fifteenth Session of the Commission on Sustainable Development (May 2007*) includes the following statements relating to hydropower's contribution: 'Energy is crucial for sustainable development, poverty eradication and achieving the internationally agreed development goals'. Action was committed to:

- 'Substantially increase, as a matter of urgency, the global share of renewable energy in the energy mix'
- 'Enhance and facilitate, as appropriate, regional cooperation in the field of generation, transmission and distribution of energy, including through sustainable exploration and utilization of regional hydroelectric potentials'.

Working through the International Renewable Energy Alliance, a partnership of the leading international organisations representing hydro, wind, solar and geothermal technologies, the mandate of the International Hydropower Association is to:

- identify the current status of hydropower worldwide;

*http://www.un.org/esa/sustdev/csd/csd15/documents/chair_summary.pdf

Figure 7-1 Estimated hydropower development by region
Source: International Hydropower Association

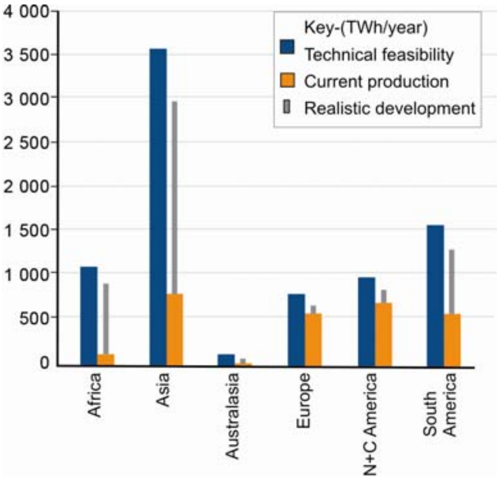


Figure 7-2 The High Aswan Dam[13]
Source: Egyptian Electricity Holding Company

- quantify the potential future contribution of hydropower;
- evaluate and promote international good practice;
- establish a framework for sustainability performance assessment;
- resolve issues and barriers that impede future development.

Present Situation and Future Potential

Global energy use has risen by 70% since 1971 and continues to increase at the rate of about 2% per year, demand coming from both developed and developing countries. There are many scenarios for future demand and the energy mix that will be needed to meet this.

In 2005, renewable energy represented one-fifth of total power generation. Hydropower is the most advanced and flexible of the renewables and represents 87% of this production. During 2005 alone, 18 GW of new hydro capacity was commissioned. Notwithstanding this, the entire renewables portfolio for heat, power and transportation offers an enormous potential. As far as hydropower resources are concerned, the IHA estimates that only one-third of the realistic potential has been developed.

As seen in Table 7-2, hydro provides some level of power generation in 160 countries. Five countries make up more than half of the world's hydropower production: Brazil, Canada, China, Russia and the USA. Taking Europe as a benchmark (proportion of production in relation to realistic feasibility), hydro can be expected to see a ten-fold increase in Africa, a three-fold increase in Asia, a doubling in South America, and an increase of about 10% in North America. Just for North America, this would equate to an additional 16 GW of new capacity, of which 11 GW is already identified in Canada. While this expansion will be determined by the needs of the North American market, future development in many less-developed regions will rely more heavily on finding long-term funding mechanisms and appropriate partnerships, thus controlling the rate of progress.

The Changing Role of Hydropower

Most of the early hydropower projects were built to provide a primary 'base load' to the power system and this pattern will continue in countries where hydropower occupies a significant share in the power generation mix. As other technologies have been introduced, hydro has tended to evolve into a supporting role -

[13] The High Aswan Dam (Fig. 7-2) and 2 100 MW powerplant has regulated flows and mitigated floods on the lower reaches of the Nile for 40 years. During this time, the plant has been the key component of the Egyptian electricity system. The powerplant is currently undergoing a major (€ 85 million) modernisation, which will enable continued generation for further decades.

Figure 7-3 The 400 MW Palmiet pump-storage scheme in the Western Cape of South Africa, located with a UNESCO biosphere reserve, protecting the unique Cape Floral Kingdom. Palmiet not only provides peaking power and ancillary services for the country's national grid, its pump-turbines also facilitate an inter-catchment water transfer, supplying water to the metropolitan district of Cape Town.
Source: Eskom

responding to gaps between supply and peak demand.

The challenge is to continuously improve hydropower technology in terms of environmental performance, materials, efficiency, operating range, and costs. From the smallest to the largest, all developments have a footprint, especially evident in the cumulative effect of many small schemes. Smaller-scale hydro plays an important role in remote areas, in community developments, and in maximising the value of multi-purpose infrastructure - applicable in both developed and developing countries. Large schemes will continue to be the most environmentally benign in supporting grid systems and powering industrial and urban centres.

The least-cost option for producers desiring additional capacity is almost always to modernise existing plants, when this is an option. Equipment with improved performance can be retrofitted, often to accommodate market demands for more flexible, peaking modes of operation. Most of the 807 GW of hydro equipment in operation today will need to be modernised by 2030.

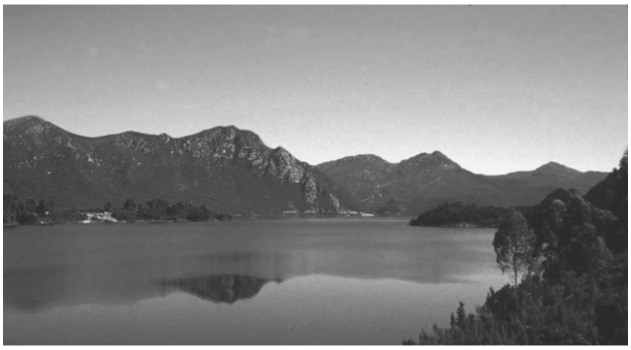
There are many recent cases of incremental hydropower, both where current capacity has been added to and where existing infrastructure has been reworked, resulting in entirely new hydropower facilities. There are 45 000 large dams in the world and the majority do not have a hydro component. While this is not always an economic option, there is a significant market niche in this area.

Development of hydro has a long-term economic advantage. With annual operating costs being a tiny fraction of the initial capital cost, hydro's autonomy from the fuel price is a distinct advantage. The flexibility of storage hydro (using reservoirs) also makes it a compelling partner to ensure security in mixed power systems. Another driver for hydro development is the increasing need for water management. Multi-purpose hydro reservoirs can bring security of water supply as well as power.

Synergy with Other Renewable Energies

Storage hydro and, in regions where the quantity of water is limited, pumped storage can solve a plethora of system challenges. It can follow load fluctuations, so that fossil-fuel plants can continue to operate at their best efficiency. Wind power produces a variable and intermittent supply and hydro can provide the firming capacity to ensure both security and quality in the system. The characteristics of geothermal plant are well suited to base-load operation; hydro's flexibility can support it by meeting peaks in demand. Similar synergies with solar, bio-generation and marine power will develop as

Figure 7-4 Lake Burbury in Tasmania, Australia – water stored in this reservoir supplies a 143 MW power plant, which provides firming capacity for the extensive wind power development on the island state
Source: Hydro Tasmania



these technologies move into larger-scale deployment. In many regions where there is a diverse mix in the power system, storage hydro and pumped storage ensure total system security and maintain the quality of supply.

Figure 7-5 The Háganga hydropower reservoir in the highlands of northern Iceland. Peaking operation of the hydro powerplants support base-load generation from the country's geothermal power stations. The example (bottom) is the 60 MW Krafla plant.
Sorce: Landsvirkjun

Climate Change and Reservoir Emissions

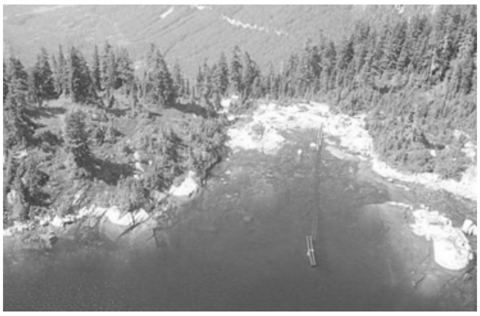
In terms of climate change, hydropower tends to have a very low greenhouse gas footprint. As water carries carbon in the natural cycle, scientists have investigated the extent to which a new reservoir might accelerate carbon emissions. In some very shallow tropical reservoirs, this may be the case, and the factor would need to be taken into consideration in the life-cycle analysis of such schemes. In contrast, many reservoirs around the world have been monitored to test their emissions, confirming that hydropower is one of the cleanest methods of power generation.

Population growth in emerging markets is both a driver and a constraint. The demand for land and water resources increases with population growth. However, water management is key to sustainable development. Many future projects will be multi-purpose, climate-mitigation structures, for drought protection and flood mitigation, in addition to power generation. By storing water, freshwater reservoirs increase water security; by maintaining reserve storage capacity, reservoirs can absorb peak flows during flood events; and, by employing hydropower generation in place of fossil-fuel technologies, a significant offset of greenhouse gas emissions can be achieved.

Hydropower Sustainability Guidelines

Finding the right balance is fundamental. Sustainability criteria demand that economic decisions incorporate environmental

Figure 7-6 A 400 metre long salmon spawning channel constructed as part of the Sechelt Creek hydropower development in British Columbia, Canada. The scheme was developed in close collaboration with the local indigenous community. An aerial view of the headwater intake for the powerplant is shown (right).
Source: Regional Power Inc.



stewardship and social justice. To give guidance, the IHA has developed Sustainability Guidelines. Supplementing these is an Assessment Protocol which sets out a system by which sustainability performance can be measured. It is expected that the Protocol will become the primary tool for certifying the sustainability of hydropower development, and the IHA is working with several international partners to progress this matter.

Sustainability assessment is applicable to both existing schemes and new developments. Europe and North America tend to have the most advanced regulatory frameworks. While comprehensive assessment is necessary, much superfluous bureaucracy is created in the development of new projects and the periodic re-licensing of existing installations. The high administration costs are a significant burden, especially for smaller companies. In Europe, both the Water Framework and Emissions Trading Directives are in need of clarification regarding hydropower. For the 'transition' countries and the developing world, regulations relating to the Kyoto mechanisms need to be better understood. In addition, financial institutions must standardise their policies to avoid unnecessary duplication and inefficiency.

Figure 7-7 The 1 240 MW Salto Caxias hydropower scheme on the Iguassu River in Brazil. Six hundred families were relocated as part of the regional development associated with this scheme. The image below captures the organic farming practice which has been adopted by the agricultural community, and the image overleaf, the new education facilities that have been established as part of the development.
Source: Companhia de Energia Elétrica do Paraná

Financing Hydropower

Many economically feasible hydropower projects are financially challenged. High up-front costs are a deterrent for investment. Also, hydro tends to have lengthy lead times for planning, permitting, and construction. When life-cycle costs are examined, however, hydro often has the best performance, with operating costs being low in comparison with the capital investment. The development of more appropriate financing models is a major challenge for the hydro sector, as is finding the optimum roles for the public and private sectors.

The main challenges relate to creating investor confidence in hydropower and reducing risk. Green markets and trading in emissions reductions will undoubtedly provide incentives in some areas. In developing markets, such as Africa, interconnection between countries and the formation of power pools will build investor confidence. Feasibility and impact assessments carried out by the public sector, prior to tenders from the developers, will ensure greater private-sector interest in future projects.

Unfortunately, investment often only materialises when the need becomes urgent - when the lights go out. Unless policymakers are better informed, much of the investment will be targeted at quick-fix solutions. The avoidance of such unsustainable development is a major challenge.

Richard Taylor
International Hydropower Association

DEFINITIONS

This chapter is restricted to that form of hydraulic energy that results in the production of electrical energy as a result of the natural accumulation of water in streams or reservoirs being channelled through water turbines. Energy from tides and waves is discussed in Chapters 13 and 14.

Annual generation and capacity attributable to pumped storage is excluded. Where such installations produce significant energy from natural run-off, the amount is included in the total for annual generation.

It must be recognised that for some countries it is not possible to obtain comprehensive data corresponding exactly to the definitions. This particularly applies to small hydro schemes, many of which are owned by small private generators. Also, not all countries use the same criteria for the distinction between small and large hydro. In this *Survey*, small hydro mainly applies to schemes of less than 10 MW. However, some countries and other sources of data make the distinction between small and large schemes at other levels.

In the tables, the following definitions apply:

Gross theoretical capability is the annual energy potentially available in the country if all natural flows were turbined down to sea level or to the water level of the border of the country (if the watercourse extends into another country) with 100% efficiency from the machinery and driving water-works. Unless otherwise stated in the notes, the figures have been estimated on the basis of atmospheric precipitation and water run-off.

Gross theoretical capability is often difficult to obtain strictly in accordance with the definition, especially where the data are obtained from sources outside the WEC. Considerable caution should therefore be exercised when using these data.

Where the gross theoretical capability has not been reported, it has been estimated on the basis of the technically exploitable capability, assuming a capacity factor of 0.40. Where the technically exploitable capability is not reported, the value for economically exploitable capability has been adopted, preceded by a ">" sign.

Technically exploitable capability is the amount of the gross theoretical capability that can be exploited within the limits of current technology.

Economically exploitable capability is the amount of the gross theoretical capability that can be exploited within the limits of current technology under present and expected local economic conditions. The figures may or may not exclude economic potential that would be unacceptable for social or environmental reasons.

Capacity in operation is the total of the rated capacities of the electric generating units that are installed at all sites which are generating, or are capable of generating, hydro-electricity.

Actual generation is the net output (excluding pumped-storage output) in the specified year.

Probable annual generation is the total probable net output of electricity at the project sites, based on the historical average flows reaching them (modified flows), net heads, and the plant capacities reported, making allowance for plant and system availability.

Capacity planned refers to all sites for which projects have been proposed and plans have been drawn up for eventual development, usually within the next 10 years.

Capacity under construction and planned relates to all units not operational but which were under construction, ordered or about to be ordered at the end of 2005.

TABLES

Table 7-1 Hydropower: capability at end-2005 (TWh/yr)

	Gross theoretical capability	Technically exploitable capability	Economically exploitable capability
Algeria	12	5	
Angola	150	65	<65
Benin	2	N	
Burkina Faso	1	1	N
Burundi	6	2	1
Cameroon	294	115	103
Central African Republic	7	3	
Chad	N	N	
Congo (Brazzaville)	> 50	10	
Congo (Democratic Rep.)	1 397	774	419
Côte d'Ivoire	46	12	6
Egypt (Arab Rep.)	> 125	> 50	50
Ethiopia	650	> 260	160
Gabon	190	76	33
Ghana	26	11	
Guinea	26	19	19
Guinea-Bissau	1	N	N
Kenya	> 24	9	
Lesotho	5	2	
Liberia	28	11	
Madagascar	321	180	49
Malawi	15	6	
Mali	12	5	
Mauritius	N	N	
Morocco	12	5	4
Mozambique	95	> 38	32
Namibia	25	10	2
Niger	3	> 1	1
Nigeria	43	32	30
Rwanda	2	1	
Senegal	11	4	2
Sierra Leone	11	7	
Somalia	2	1	
South Africa	73	14	5
Sudan	48	19	2
Swaziland	4	1	N
Tanzania	47	40	13

Table 7-1 Hydropower: capability at end-2005 (TWh/yr)

	Gross theoretical capability	Technically exploitable capability	Economically exploitable capability
Togo	4	2	
Tunisia	1	N	N
Uganda	> 18	> 13	
Zambia	53	30	11
Zimbabwe	44	18	
Total Africa	**> 3 884**	**> 1 852**	
Belize	1	N	N
Canada	2 216	981	536
Costa Rica	223	43	20
Cuba	3	1	
Dominica	N	N	N
Dominican Republic	50	9	6
El Salvador	7	5	
Greenland	800	120	
Grenada	N	N	
Guatemala	54	22	
Haiti	4	1	N
Honduras	16	7	
Jamaica	1	N	
Mexico	135	49	32
Nicaragua	33	10	7
Panama	26	> 12	12
United States of America	4 485	1 752	501
Total North America	**8 054**	**> 3 012**	
Argentina	354	130	
Bolivia	178	126	50
Brazil	3 040	1 488	811
Chile	227	162	
Colombia	1 000	200	140
Ecuador	167	134	106
Guyana	> 64	> 26	26
Paraguay	130	106	101
Peru	1 577	395	260
Surinam	32	13	
Uruguay	32	10	
Venezuela	320	246	130
Total South America	**> 7 121**	**> 3 036**	

Table 7-1 Hydropower: capability at end-2005 (TWh/yr)

	Gross theoretical capability	Technically exploitable capability	Economically exploitable capability
Armenia	22	7	4
Azerbaijan	44	16	7
Bangladesh	4	2	1
Bhutan	> 263	99	56
Cambodia	88	30	5
China	6 083	2 474	1 753
Cyprus	59	24	
Georgia	180	80	40
India	2 638	660	600
Indonesia	2 147	402	40
Japan	718	136	114
Kazakhstan	170	62	29
Korea (Republic)	52	26	19
Kyrgyzstan	163	99	55
Laos	232	63	
Malaysia	230	123	
Mongolia	56	22	
Myanmar (Burma)	> 342	130	
Nepal	733	151	15
Pakistan	480	219	
Philippines	47	20	18
Sri Lanka	18	7	7
Taiwan, China	103	20	12
Tajikistan	527	> 264	264
Thailand	41	16	15
Turkey	433	216	130
Turkmenistan	24	5	2
Uzbekistan	88	27	15
Vietnam	300	123	78
Total Asia	**> 16 285**	**> 5 523**	
Albania	40	15	6
Austria	150	75	56
Belarus	8	3	1
Belgium	1	N	N
Bosnia-Herzogovina	70	24	19
Bulgaria	27	15	12
Croatia	20	9	8
Czech Republic	13	4	

Table 7-1 Hydropower: capability at end-2005 (TWh/yr)

	Gross theoretical capability	Technically exploitable capability	Economically exploitable capability
Denmark	N	N	N
Estonia	2	N	N
Faroe Islands	1	N	N
Finland	48	23	14
FYR Macedonia	9	5	
France	270	100	70
Germany	120	25	20
Greece	80	15	12
Hungary	10	8	4
Iceland	184	64	40
Ireland	1	1	1
Italy	340	105	65
Latvia	7	4	3
Lithuania	5	3	2
Luxembourg	N	N	N
Moldova	2	1	1
Netherlands	1	N	N
Norway	560	200	187
Poland	23	14	7
Portugal	32	25	20
Romania	70	35	25
Russian Federation	2 295	1 670	852
Serbia	37	19	18
Slovakia	10	7	6
Slovenia	19	9	7
Spain	150	66	32
Sweden	130	100	85
Switzerland	125	43	41
Ukraine	45	24	17
United Kingdom	40	3	1
Total Europe	**4 945**	**2 714**	
Iran (Islamic Rep.)	176	70	50
Iraq	225	90	67
Israel	N	N	
Jordan	4	2	
Lebanon	2	1	
Syria (Arab Rep.)	11	5	4
Total Middle East	**418**	**168**	

Table 7-1 Hydropower: capability at end-2005 (TWh/yr)

	Gross theoretical capability	Technically exploitable capability	Economically exploitable capability
Australia	265	100	30
Fiji	3	1	
French Polynesia	1	N	N
New Caledonia	2	1	N
New Zealand	46	37	24
Papua New Guinea	175	49	15
Solomon Islands	3	> 1	
Western Samoa	N	N	N
Total Oceania	**495**	**> 189**	
TOTAL WORLD	**> 41 202**	**> 16 494**	

Notes:

1. A quantification of hydropower capability is not available for a number of countries for which capacity and generation are shown in Table 7-2.
2. As the data available on economically exploitable capability do not cover all countries, regional and global totals are not shown for this category.
3. Sources: WEC Member Committees, 2006/7; *Hydropower & Dams World Atlas 2006*, supplement to *The International Journal on Hydropower & Dams*, Aqua~Media International; estimates by the Editors

Table 7-2 Hydropower: status of development at end-2005 (all schemes)

	In operation		Under construction		Planned	
	Capacity	Actual generation in 2005	Capacity	Probable annual generation	Capacity	Probable annual generation
	(MW)	(GWh)	(MW)	(GWh)	(MW)	(GWh)
Algeria	275	555				
Angola	440	2 219			610 - 16 500	
Benin	65	172	100		150	
Burkina Faso	32	102			75	
Burundi	46	150			225	
Cameroon	723	3 772			455	
Central African Republic	19	120			20 - 137	
Chad					6	
Comoros	1	2				
Congo (Brazzaville)	89	352	120		1 621	
Congo (Democratic Rep.)	2 406	5 800			42 776	271 000

Table 7-2 Hydropower: status of development at end-2005 (all schemes)

	In operation		Under construction		Planned	
	Capacity	Actual generation in 2005	Capacity	Probable annual generation	Capacity	Probable annual generation
	(MW)	(GWh)	(MW)	(GWh)	(MW)	(GWh)
Côte d'Ivoire	606	1 433			270	1 116
Egypt (Arab Rep.)	2 850	12 644	110	780	30	180
Equatorial Guinea	1	2				
Ethiopia	662	2 848	3 050	10 457	1 250	4 909
Gabon	170	814			590	3 640
Ghana	1 198	6 100	90		1 205	
Guinea	129	445			836	3 940
Kenya	677	2 869	440		70	
Lesotho	76	200			26	
Madagascar	105	540	12		4	
Malawi	283	1 100			365	
Mali	155	500			370	
Mauritania	30	120				
Mauritius	59	100				
Morocco	1 498	1 597	44		5	
Mozambique	2 136	11 548			2 898 - 3 898	
Namibia	249	890			360	1 792
Niger					125	
Nigeria	1 938	8 200	52		4 850	
Réunion	125	500				
Rwanda	27	90			104	
São Tomé & Príncipe	6	10				
Senegal	64	256				
Sierra Leone	4	19	50		85	
Somalia	5	10				
South Africa	653	1 141				
Sudan	323	840	1 250		300	
Swaziland	60	124	19		20	
Tanzania	561	1 800			580	3 110
Togo	66	175				
Tunisia	62	145				
Uganda	318	1 986	330		250 - 777	
Zambia	1 698	8 445			2 010	
Zimbabwe	754	3 000	1		1 360	
Total Africa	**21 644**	**83 735**	**5 668**			

Table 7-2 Hydropower: status of development at end-2005 (all schemes)

	In operation		Under construction		Planned	
	Capacity	Actual generation in 2005	Capacity	Probable annual generation	Capacity	Probable annual generation
	(MW)	(GWh)	(MW)	(GWh)	(MW)	(GWh)
Belize	25	80	7			
Canada	71 978	358 605	1 460	6 906	11 538	54 579
Costa Rica	1 296	6 565	340		880	
Cuba	57	80	9		1	
Dominica	8	28				
Dominican Republic	412	1 900	53		405	
El Salvador	410	1 414				
Greenland	32	185	8		8	
Grenada					1	
Guadeloupe	7	26				
Guatemala	644	2 500	162		2 349	
Haiti	70	280				
Honduras	478	1 761	105		483	
Jamaica	24	78			80	
Mexico	10 285	27 967	754	1 924	2 050	3 757
Nicaragua	111	437			1 767	
Panama	845	3 779			200	
Puerto Rico	85	260				
St Vincent & the Grenadines	6	23				
United States of America	77 354	269 587	8	35	16	70
Total North America	**164 127**	**675 555**	**2 906**			
Argentina	9 921	34 192			2 400	14 000
Bolivia	458	1 424	90		700	
Brazil	71 060	337 457	4 997	23 100	36 635	169 440
Chile	4 695	25 489	300		3 000	
Colombia	9 000	37 000	660		10 000	
Ecuador	1 773	6 883	452		412	
French Guiana	116	426				
Guyana	1	1	105		1 150	
Paraguay	7 410	51 156			1 945	11 197
Peru	3 207	17 977	230	1 100	1 079	
Surinam	120	600			532 - 2 230	
Uruguay	1 538	6 684				
Venezuela	14 413	77 229	2 250	12 100	2 964	13 400
Total South America	**123 712**	**596 518**	**9 084**			

Table 7-2 Hydropower: status of development at end-2005 (all schemes)

	In operation		Under construction		Planned	
	Capacity	Actual generation in 2005	Capacity	Probable annual generation	Capacity	Probable annual generation
	(MW)	(GWh)	(MW)	(GWh)	(MW)	(GWh)
Afghanistan	260	530			42	
Armenia	1 035	1 982	5		396	
Azerbaijan	1 025	2 470			314	
Bangladesh	230	800			100	
Bhutan	445	2 050	1 020		1 660 - 7 805	
Cambodia	12	41	1		195	
China	100 000	337 000	50 000		80 000	
Cyprus	1	2				
Georgia	2 700	6 400	724		400	
India	31 982	97 403	13 245	52 685	8 860	33 050
Indonesia	3 221	9 831	135		802	
Japan	27 759	80 715	745	1 818	19 052	47 551
Kazakhstan	2 247	8 610			350	
Korea (Democratic People's Rep.)	4 750	22 800				
Korea (Republic)	1 584	3 674				
Kyrgyzstan	2 910	10 644	360		1 900	
Laos	673	3 828	2 011		3 000 - 5 000	
Malaysia	2 078	4 400	2 400		510	
Mongolia	3	4	11		13 - 345	
Myanmar (Burma)	745	1 639	1 786		8 000	
Nepal	560	2 511	69			
Pakistan	6 499	25 671	734		8 100 - 25 671	
Philippines	2 450	7 785			660	
Sri Lanka	1 207	3 173	150	409	830	4 464
Taiwan, China	1 910	4 054	447		440	
Tajikistan	4 528	15 000	670		5 000 - 27 000	
Thailand	3 476	5 801				
Turkey	12 788	35 065	3 197	10 518	20 667	73 459
Turkmenistan	1	3				
Uzbekistan	1 420	6 286	249		913	
Vietnam	4 198	18 000	7 768		4 614	
Total Asia	**222 697**	**718 172**	**85 727**			
Albania	1 450	4 300	60		690 - 967	
Austria	11 811	39 019	1 200	2 400	88	400
Belarus	12	24			200 - 210	

Table 7-2 Hydropower: status of development at end-2005 (all schemes)

	In operation		Under construction		Planned	
	Capacity	Actual generation in 2005	Capacity	Probable annual generation	Capacity	Probable annual generation
	(MW)	(GWh)	(MW)	(GWh)	(MW)	(GWh)
Belgium	95	241				
Bosnia-Herzogovina	2 411	6 200	130		200 - 450	
Bulgaria	2 874	3 387	80	196		
Croatia	2 056	6 330	40	94	43	220
Czech Republic	1 019	2 401				
Denmark	11	23	N	N	N	N
Estonia	8	43	1		2 - 4	
Faroe Islands	31	86				
Finland	3 000	13 600	21	20	154	247
FYR Macedonia	516	1 500	36		698	
France	25 526	56 245	N	N	N	N
Germany	4 525	27 700	121		20	
Greece	3 060	4 920	600			
Hungary	55	205				
Iceland	1 160	7 014	690	4 540	100	630
Ireland	249	640			5	
Italy	17 326	36 067	45	144	190	576
Latvia	1 561	3 325			24	64
Lithuania	101	385				
Luxembourg	39	96				
Moldova	60	318				
Netherlands	38	88				
Norway	27 698	136 400	300		859	
Poland	850	1 953	3	13	60	300
Portugal	4 818	5 118			1 042	
Romania	6 346	20 103	750	2 532	860	2 535
Russian Federation	45 700	165 000	5 648		8 000	36 400
Serbia	2 891	11 924				
Slovakia	2 547	4 630			138	600
Slovenia	979	3 461	75	175	415	1 461
Spain	18 674	23 215	51	35	170	118
Sweden	16 100	72 100	N	N	N	N
Switzerland	13 356	30 128	221	175		
Ukraine	4 736	12 320				
United Kingdom	1 513	4 961				

Table 7-2 Hydropower: status of development at end-2005 (all schemes)

	In operation		Under construction		Planned	
	Capacity	Actual generation in 2005	Capacity	Probable annual generation	Capacity	Probable annual generation
	(MW)	(GWh)	(MW)	(GWh)	(MW)	(GWh)
Total Europe	**225 202**	**705 470**	**10 072**			
Iran (Islamic Rep.)	5 012	10 627	10 491	19 994	12 254	25 128
Iraq	260	1 862				
Israel	7	30			2	
Jordan	10	50			400 - 800	
Lebanon	280	850	76			
Syria (Arab Rep.)	1 616	3 445				
Total Middle East	**7 185**	**16 864**	**10 567**			
Australia	7 670	15 600				
Fiji	85	421	3		40	
French Polynesia	47	164			10	
New Caledonia	78	399			18	
New Zealand	5 346	23 238	16	105	186	974
Palau	10	30				
Papua New Guinea	222	513			11	
Solomon Islands	N	1			20	
Vanuatu	1	5			1	
Western Samoa	12	54				
Total Oceania	**13 471**	**40 425**	**19**			
TOTAL WORLD	**778 038**	**2 836 739**	**124 043**			

Notes:

1. As the data available on the probable annual generation of capacity under construction, and on planned capacity and generation, do not cover all countries or are quoted in terms of a range, regional and global totals are not shown for these categories.
2. Sources: WEC Member Committees, 2006/7; *Hydropower & Dams World Atlas 2006*, supplement to *The International Journal on Hydropower & Dams*, Aqua~Media International; national and international published sources; estimates by the Editors

Table 7-3 Hydropower: status of development at end-2005 for small-scale schemes (<10MW)

		In operation		Under construction and planned	
	Economically exploitable capability	Capacity	Actual generation in 2005	Capacity	Probable annual generation
	(GWh/yr)	(MW)	(GWh)	(MW)	(GWh)
Africa					
Algeria		54	17		
Côte d'Ivoire		5	11		
Egypt (Arab Rep.)	180				
Ethiopia		7	17		
Gabon		6	23	4	40
Guinea	79	11	12		
Namibia	19	N	N		
South Africa		34			
North America					
Canada		978			
Mexico	12 000	109	479		
United States of America		2 838	10 701	16	70
South America					
Argentina		92	338	229	1 193
Brazil	17 169	1 429	6 700	1 800	8 670
Paraguay	1				
Peru		228	1 002	10	
Venezuela		2	3	5	22
Asia					
Indonesia		21	56	17	
Japan		3 478		106	478
Korea (Republic)		56	179		
Nepal		19			
Sri Lanka	1 226	97	277	114	350
Taiwan, China		71			
Thailand	208	76	212	10	23
Turkey	8 736	173	675	1 086	4 940
Europe					
Austria	10 000	994	3 999	< 200	700
Bulgaria		207			
Croatia	250	32	110		
Czech Republic		277	1 071		

Table 7-3 Hydropower: status of development at end-2005 for small-scale schemes (<10MW)

		In operation		Under construction and planned	
	Economically exploitable capability	Capacity	Actual generation in 2005	Capacity	Probable annual generation
	(GWh/yr)	(MW)	(GWh)	(MW)	(GWh)
Denmark		11	23		
Finland	1 400	300	1 240		
France		2 024	5 823		
Hungary	200	11	8		
Iceland		53	272		
Italy		2 405	7 616	164	676
Latvia	70	26	62	24	64
Lithuania	100	25	66	6	16
Luxembourg		28	73		
Poland		72	248		
Portugal		305	376	100	
Romania		244	729		
Russian Federation		66			
Serbia		35	15		
Slovakia	450	70	250	30	
Slovenia	475	143	379	11	
Spain		1 788	4 729	450	1 271
Sweden		985	3 800		
Switzerland	190 - 300	56	246		
Ukraine		66	252		
Middle East					
Iran (Islamic Rep.)		58	116	106	443
Israel		6	30		
Jordan		10			
Syria (Arab Rep.)	100	33	20	30	60
Oceania					
New Zealand	450	108	509	7	31

Notes:

1. The data on small-scale schemes are those reported by WEC Member Committees. They thus constitute a sample, reflecting the information available in particular countries: they should not be considered as complete, or necessarily representative of the situation in each region. For this reason, regional and global aggregates have not been computed.
2. Sources: WEC Member Committees, 2006/7

COUNTRY NOTES

The Country Notes on Hydropower have been compiled by the Editors, drawing principally upon the 2006 edition of the *Hydropower & Dams World Atlas,* supplement to *The International Journal on Hydropower & Dams,* published by Aqua~Media International, together with information provided by WEC Member Committees in 2006/7 and various national published sources.

Argentina

Hydropower & Dams World Atlas 2006 quotes Argentina's gross theoretical hydropower potential as 354 000 GWh/yr; its technically feasible potential is put at 130 000 GWh/yr, of which about 26% has so far been exploited.

Hydro output in 2005 was 34.2 TWh, in the context of an end-year installed capacity of 9 921 MW.

A substantial portion of Argentina's hydro capacity is accounted for by its 50% share in two bi-national schemes: Salto Grande (installed capacity 1 890 MW), shared with Uruguay and Yacyretá (3 100 MW), shared with Paraguay. The latter plant is currently operating at a reduced head, with its capacity restricted to 1 800 MW.

The Argentinian WEC Member Committee reports that there were no hydro plants under construction at end-2005, but that some 2 400 MW of new capacity is planned. The bulk of this figure is accounted for by Argentina's 50% share in two bi-national projects: Garabí (1 500-1 890 MW) on the Uruguay river, shared with Brazil, and Corpus Christi (2 880 MW) on the Paraná, shared with Paraguay.

Installed capacity of small-scale hydro (up to 30 MW in this case) came to 92 MW at end-2005, with an output of 338 GWh; a further 229 MW is reported as planned.

Australia

It should be noted that Australia is the driest inhabited continent on earth, with over 80% of its landmass receiving an annual average rainfall of less than 600 mm/yr and 50% less than 300 mm/yr. A high variability in rainfall, evaporation rates and temperatures also occurs between years, resulting in Australia having very limited and variable surface and groundwater resources.

The economically exploitable capability is estimated by *Hydropower & Dams World Atlas* as 30 TWh/yr, of which more than 60% has already been harnessed. According to the same source, no new hydro plants are under construction or planned.

The prospects for large-scale hydroelectric projects in Australia are limited, principally because most available sites have already been developed and, in some cases, have required a compromise to be reached on wilderness preservation or other environmental factors. There are, however, development opportunities associated with hydropower projects. These opportunities are in the refurbishment of existing plant and equipment. Many turbines are now on average approaching 50 years old and to remain serviceable need maintenance and/or refurbishment. Indeed, one of the intentions of the federal Government's Renewable Energy (Electricity) Act 2000 has been to give recognition to large-scale hydro as a renewable energy resource, and to the possibility that hydro could play an important role in meeting the target of 9 500 GWh of new renewable energy by 2010.

In addition to refurbishment opportunities, there are also prospects for increased contributions from mini-hydro projects. Private development of small-scale grid-connected hydro has been taking place in Australia since the mid-1980s, with the first significant project undertaken by Melbourne Water on the Thompson Dam.

Austria

The use of hydro-power as a clean and emission-free way of generating electricity has a long tradition in Austria. Hydro-electric power represents about 60% of the domestic electricity generated and about one-third of the total of energy generated.

In addition to a number of large river power stations along the Danube, storage power stations were built in the western alpine regions which largely serve to cover the power demands in winter. In recent years, assessing the environmental compatibility has been the most important consideration when constructing a plant.

During the summer, practically the entire demand for electricity can be catered for by hydro-electric stations and Austria even exports electricity.

Small hydro up to 10 MW has been granted tariffs of between 3.15 and 6.25 cents per kWh, depending on whether the plant is new or refurbished. There is a new subsidy for middle-scale hydro from 10 to 20 MW, with a maximum of € 6 million per plant.

Bolivia

Bolivia has a considerable hydro potential, its technically feasible potential being assessed at 126 TWh/yr, of which 50 TWh/yr is considered to be economically exploitable. Only a minute proportion of the potential has been harnessed so far - 2005 hydro capacity was 458 MW, with an output of about 1.4 TWh.

According to the *Hydropower & Dams World Atlas 2006*, 90 MW of additional hydro capacity was under construction at the end of 2005, mainly comprising the Rio Taquesi project (83.5 MW). The approximately 700 MW of hydro capacity planned included new plants at San José (126 MW), Misicuni (120 MW) and Palillada (80 MW), as well as the updating of several existing HPPs.

Brazil

Hydroelectric power is one of Brazil's principal energy assets: the republic has by far the largest hydropower resources on the continent. The Brazilian WEC Member Committee reports that gross theoretical capability exceeds 3 000 TWh/yr, with an economically exploitable capability of over 800 TWh/yr, of which over 40% has been harnessed so far. Hydro output in 2005 was 337 TWh, which accounted for 84% of Brazil's electricity generation.

Hydro generating capacity more than doubled between 1980 and 1999, partly through gradual commissioning of the huge Itaipú scheme (total capacity 12 600 MW), which came into operation between 1984 and 1991. Brazil shares Itaipú's output with its neighbour Paraguay, which sells back to Brazil the surplus power remaining after its own electricity needs have been satisfied.

At the end of 2005, Brazil had 5 GW of hydro capacity under construction, including a major (4 125 MW) extension of capacity at Tucuruí and two additional 700 MW units at Itaipú. Nearly 37 GW of further hydro capacity is planned for future development. The 19th 700 MW unit entered commercial operation at Itaipú in September 2006, bringing its total capacity up to 13 300 MW.

Within the overall picture outlined above, small-scale hydro (since 1998, defined in Brazil as plants with a capacity of < 30 MW) has an economically exploitable capability of about 17 TWh/yr, 39% of which had been exploited by capacity installed as at end-2005. The 1 429 MW of small-scale hydro currently in place will be augmented by 1 800 MW additional capacity which is under construction or planned. The legislation in force anticipates the granting of incentives for small hydro-electric stations (systems under 30 MW), in order to increase competition in the Brazilian electricity market.

Bulgaria

The Bulgarian WEC Member Committee reports a gross theoretical capability of about 26.5 TWh/yr, of which the technically exploitable capability is just over 15 TWh/yr; no economically exploitable level is quoted, but *Hydropower & Dams World Atlas 2006* provides an estimate of about 12 TWh/yr. Hydro-electric output in 2005 is given as 3 387 GWh. This level of generation implies that nearly 30% of Bulgaria's economic hydro potential has so far been utilised. It also implies a low capacity factor, in the region of 15%. As indicated by the Member Committee for the 2004 *Survey*, there are several reasons for the low capacity factors of the hydropower plants:

- the design water quantities were overestimated;
- the plants are used predominantly for regulation purposes;
- great quantities of water are diverted to supply households, agriculture and industry;
- the equipment is in poor condition owing to the low priority given to maintenance.

At the end of 2005 there was 207 MW of generating capacity at small-scale hydro plants (<10MW). For the present *Survey* the Member Committee has reported that, pursuant to an ordinance under Article 36, Paragraph 3 of the Energy Act, the public provider and public suppliers will be obliged to purchase at preferential prices electricity generated in plants using renewable energy sources, including hydro-electric plants, with total installed capacity up to 10 MW.

Cameroon

The technically exploitable hydro capability (115 000 GWh) is the fourth largest in Africa but the current level of utilisation of this potential is, like that in other hydro-rich countries in the continent, very low. Within a total hydro capacity of 723 MW, Cameroon's major stations are Song Loulou (installed capacity 396 MW) and Edéa (264 MW). Total electrical output in 2005 was 3 772 GWh, implying a capacity factor of nearly 0.60.

The Cameroon WEC Member Committee reports that development plans exist for new hydro stations at Nachtigal (230 MW), Menveele (120 MW), Lompangar (25 MW) and Birni à Warak (80 MW).

Canada

Canada possesses enormous hydropower potential. In 2005, 60% of its electricity generation was provided by hydroelectric power plants, which generated more than 358 TWh, up from 337 TWh in 2004. Canada is one of the largest hydro producers in the world, and had an installed capacity of 71 978 MW at the end of 2005.

There are many significant hydroelectric projects under way. In total, these projects will increase hydro generation capacity by more than 3 500 MW.

In British Columbia, there are three significant expansions/installations currently being undertaken: the expansion of the Brilliant Dam and power plant on the Kootenay River near Castlegar will increase its capacity by 120 MW when commissioned (Spring 2007); the Forrest Kerr run-of-river hydro facility, with a capacity of 115 MW, is expected to be completed in early 2008; upgrades to the generators at the Mica Dam hydro station will add about 275 MW by 2009. The Waneta Expansion project will commence construction in 2007 pending approvals, and would add a further 435 MW.

In Manitoba, upgrades at the Kelsey generating station will add 84 MW by 2010, the first unit was started in 2006. Construction of the Wuskwatim generating station commenced in August 2006, and will add 200 MW.

In Ontario, upgrades at the Sir Adam Beck II generating station between 1996 and 2005 resulted in an increased capacity of 208 MW, and the Niagara Tunnel Project will increase the capacity factor at Sir Adam Beck II, resulting in an expected 1 600 GWh/yr extra generation by 2009. The recently completed rehabilitation at the R.H. Saunders generating station resulted in a capacity increase of 132 MW.

While plans exist for new hydro capacity in Newfoundland and Labrador, there has been no recent construction.

Quebec is the largest developer of hydroelectricity in Canada. In 2005, the 77 m high Toulnustouc Dam and generating station was completed, adding 526 MW of capacity. The Mercier project is to be completed in late 2007 on the Gatineau River north of Maniwaki, and will add 50 MW. The Eastmain-1 hydro station was fully commissioned in Spring 2007, adding a further 480 MW. The Eastmain-1-A/Rupert diversion project was launched in January 2007; it will add 888 MW when commissioned in 2010/11. The Péribonka hydro project will be commissioned in 2008, adding 385 MW. Two run-of-river projects are being constructed, at Chute Allard (62 MW) and Rapides-des-Coeurs (76 MW), and should be commissioned by 2008. Refurbishment at Outardes-3 and -4 will increase capacity by 310 MW. Upgrades at the La Tuque power plant will increase capacity by 51 MW.

Installed capacity of small hydro plants of less than 10 MW totalled 978 MW at end- 2004. These facilities are located throughout the country, particularly in British Columbia, Ontario, Quebec, Nova Scotia, Newfoundland and Labrador.

In Canada, the Income Tax Act defines small hydro as any hydro facility with less than 50 MW, and allows for the accelerated depreciation of those facilities. Under this definition, the installed capacity was 3 400 MW in 2005. An inventory prepared by Natural Resources Canada identified 5 500 technically feasible sites, with a potential of 11 000 MW. However, of these, only about 15% are currently both technically and economically feasible. It is estimated that by 2011, a further 2 000 MW of small hydro capacity, below 50 MW, could be installed.

In 2004, the Ontario Government awarded one contract to a small hydro facility that guarantees the developer a fixed price and fixed term for its production. Small hydro facilities qualify for tax incentives with accelerated depreciation treatment.

Most provinces are now using a competitive process to increase renewable energy supply, including small hydro. Three provinces (Nova Scotia, New Brunswick and Prince Edward Island) have legislated Renewable Portfolio Standards, and effective 1 April 2007, the federal Government provides incentives for renewable electricity generation projects.

Chile

There is substantial hydropower potential, with the technically exploitable capability estimated at about 162 TWh/yr, of which about 15% has so far been exploited. Hydro output in 2005 was 25.9 TWh, equivalent to just over 50% of Chile's total net electricity generation.

The 570 MW Ralco station in the Upper Bío Bío Valley, Chile's first new hydro plant for over eight years, came into operation in 2004. *Hydropower & Dams World Atlas 2006* quotes Chile's hydro capacity as 4 695 MW, with 300 MW under construction and about 3 000 MW planned. In this latter category were the following projects: Baker (1 000 MW), Pascua (1 200 MW), Neltume (400 MW), Choshuenco (150 MW) and Punilla (100 MW).

China

China's hydroelectric resources are vast, however measured: its gross theoretical potential exceeds 6 000 TWh/yr, its technically feasible potential is put at 2 474 TWh/yr while its economically feasible potential has been assessed at 1 753 TWh/yr - in all instances, far larger than that of any other country in the world. Current hydro output (including output from pumped-storage schemes) exceeds 400 TWh/yr, contributing 15-16% to the republic's electricity generation.

Hydropower & Dams World Atlas 2006 reported that in early 2006 some 50 000 MW of hydro capacity was under construction. The largest hydro project is the Three Gorges complex (18 200 MW), which is gradually being brought into operation, with completion scheduled for 2010. Three Gorges generated 49.2 TWh in 2006, as much as all of Italy's hydro stations produce annually.

Other major hydro projects listed as under construction, with completion expected in the period 2009-2013, include Shuibuya (1 840 MW), Pubugou (3 600 MW), Longtan (5 400 MW), Xiloudu (1 500 MW), Laxiwa (4 200 MW), Xiaowan (4 200 MW) and Goupitan (3 000 MW).

China has about 8 300 MW of pumped-storage capacity, with 7 600 MW under construction.

Colombia

The theoretical potential for hydropower is very large, being estimated to be 1 000 TWh/yr, of which 20% is classed as technically feasible. The economically exploitable capability has been evaluated as 140 TWh/yr: hydro output in 2005 represented about a quarter of this potential, and accounted for around two-thirds of Colombia's electricity generation.

Construction of Porce III (660 MW) began in 2006. Around 10 000 MW of new capacity is at the planning stage, for medium- to long-term implementation, including Sogamoso (840 MW), Nechí (750 MW), Miel II (411 MW), Quimbo (400 MW), Andaquí (705 MW) and Porce IV. In addition, there is estimated to be scope for uprating existing HPPs by a total of around 500 MW.

Congo (Democratic Republic)

The assessed potential for hydropower is by far the highest in Africa, and one of the highest in the world. The gross theoretical potential of the Congo River is almost 1 400 TWh/yr and the technically feasible capacity about 100 000 MW. The current level of rated hydroelectric capacity is equivalent to less than 3% of this latter capacity. Hydro provides virtually the whole of the country's electricity.

The national power authority SNEL has 17 hydro plants, with a total rated capacity of 2 410 MW; its largest stations are Inga I (351 MW) and Inga II (1 424 MW). The effective capacity at SNEL's hydro plants has recently been only about half their rated level, owing to problems in maintenance and refurbishment.

A significant increase in capacity would be provided by Inga III (3 500 MW), which is currently in the stage of feasibility studies. There is also a huge scheme (Grand Inga, 39 000 MW) for the installation of up to 52 generators of 750 MW each, incorporating the supply of electricity to other parts of Africa via new long-distance transmission lines. Both generating plant and transmission network have been the subject of preliminary investigations and pre-feasibility studies.

These studies identified three major African interconnection projects:

- Northern Highway (Inga to Egypt);
- Southern Highway (Inga to South Africa);
- Western Highway (Inga to Nigeria).

These electricity Highways would supply the five African power pools: SAPP, WAPP, PEAC, EAPP and COMELEC.

The World Energy Council is facilitating the development of the Inga River hydropower projects. As a first step, WEC convened an International high level Forum on the Grand Inga Projects in Gaborone, Botswana, 16-17 March 2007, which produced a Draft Action Plan. In due course the final plan will be submitted by the WEC to the G8 and other international and regional organisations and institutions.

Costa Rica

For a country with a surface area of only 51 100 km^2, Costa Rica has a surprisingly large hydroelectric potential. Its gross theoretical potential is estimated at 223 TWh/yr, within which 43 TWh/yr has been assessed as technically feasible.

Aggregate hydro capacity was 1 296 MW at end-2005, equivalent to about 70% of Costa Rica's generating capacity. Several new hydro plants are under construction or planned: nearing completion are Cariblanco (70 MW) and Pirris (128 MW), together with two BOT schemes: La Joya (50 MW) and General (39 MW). Two projects at earlier stages of planning are Toro 3 (50 MW) and Boruca-Veraguas (830 MW).

Czech Republic

The overall potential for all sizes of hydropower is quite modest (technically exploitable capability: 3 978 GWh/yr). Total hydroelectricity output in 2005 was 2 401 GWh, representing 60% of the technical potential. Hydropower furnishes about 3% of the republic's electricity generation.

A relatively high proportion (nearly 40%) of the technically exploitable capability is classified as suitable for small-scale schemes; installed capacity in this category at the end of 2005 was

277 MW, equivalent to about 27% of the Czech Republic's hydro capacity. Actual generation from small-scale schemes in 2005 accounted for nearly 45% of hydro output, reflecting the higher average capacity factor achieved by small hydro compared with the larger stations.

Ethiopia

There are enormous resources for hydro generation, the gross theoretical potential (650 TWh/yr) being second only to Congo (Democratic Republic) in Africa. *Hydropower & Dams World Atlas 2006* has revised its figure for Ethiopia's economically feasible potential from 260 to 161 TWh/yr, of which 10% represents the potential for small-scale hydro installations. Hydro output in 2005 was less than 3 TWh, a minute fraction of the assessed potential. Currently, hydroelectricity provides around 99% of Ethiopia's electricity.

Ethiopia's WEC Member Committee reports that the following hydropower plants were under construction at end-2005:

Plant	Capacity (MW)	Average Generation (GWh/yr)
Gilgel Gibe II	420	1 600
Tekeze	300	917
Beles	460	1 540
Gilgel Gibe III	1 870	6 400
Total	**3 050**	**10 457**

Planned hydropower plants comprised:

Plant	Capacity (MW)	Average Generation (GWh/yr)
Chemoga Yeda I & II	440	1 391
Halele Werabesa I & II	374	2 233
Aleltu East	189	657
Amerti Neshe	97	215
Gojeb	150	413
Total	**1 250**	**4 909**

The Ethiopian energy policy (1994) places high priority on the development of small hydropower resources. The off-grid rural electrification strategy has indicated the need for promotion of micro-hydropower (less than 900 kW). The off-grid rural electrification programme provides loan finance for small hydropower projects.

Finland

The Finnish WEC Member Committee reports that a significant proportion of the natural flows suitable for power production are located in preservation areas. According to the study *Volume and potential of hydropower in Finland*, 7 400 GWh/yr of the technically exploitable capability (22 600 GWh/yr) is located in conserved water flows.

The same study estimates that the following amounts of small-scale (<10 MW) hydropower capacity/generation will be installed during the period to 2020:

- 10 MW (28 GWh/yr) in 2005-2010
- 20 MW (48 GWh/yr) in 2010-2015

- 53 MW (187 GWh/yr) in 2015-2020

The Finnish Government can aid the building and production of small-scale hydropower. In practice, investment aid has been around 20%, and it has only been granted to plants with a capacity of less than 1 MW. These plants also receive tax subsidies (€ 4.2/MWh) for the electricity that they produce.

France

France is one of Western Europe's major producers of hydroelectricity, but its technically feasible capacity has now been very largely exploited. No more medium/large hydro plants are under construction or planned.

The total installed capacity of small-scale (less than 10 MW) plants is around 2 000 MW, which generated 5.8 TWh in 2005. There are, on the other hand, some 280 hydro plants of greater than 10 MW, with an aggregate installed capacity of more than 23 000 MW.

An Arrêté issued on 7 July 2006 in the context of the long-term plan for investments in electricity generation quotes the following targets for total hydropower (including plants of less than 10 MW, but excluding pumped storage): 500 MW additional capacity by 2010; and an additional 2 000 MW (including the aforementioned 500) by 2015. The same quantitative objectives have been set for pumped-storage plants in these years.

A buy-back tariff (Arrêté dated 25 June 2006) is in operation for hydro-electric installations with a capacity of less than 12 MW.

Gabon

The Gabonese WEC Member Committee reports that the country has numerous watercourses, with a total area of nearly 10 000 km^2. Gabon's technically exploitable hydro potential is more than 76 000 GWh/yr. Only around 1% of this potential is presently exploited.

Hydropower plants in operation at end-2005 were as follows:

Plant	Capacity (MW)	Average Generation (GWh/yr)
Kinguélé	58	410
Tchimbélé	68	260
Poubara 1	18	145
Poubara 2	18	145
Mbigou	0.3	1
Médouneu and Bongolo	0.2 and 5.4	12
Total	**167.9**	**973**

Ghana

There are 17 potential hydro sites, of which only Akosombo (upgraded in 2005 from 912 to 1 038 MW) and Kpong (160 MW) have so far been developed. Construction of the 400 MW Bui dam on the Black Volta river is expected to get under way shortly. In November 2006 the Minister of Energy was reported as saying that Ghana was close to finalising a deal with China's Sino Hydro

Corporation to construct Bui, although negotiations were continuing with regard to financing. In April 2007 the two parties signed an Engineering, Procurement and Construction (EPC) agreement, with work on the combined hydro/irrigation project expected to be started during the year, with completion in about five years' time.

Electricity generation in Ghana is a responsibility of the Volta River Authority, established in 1961. The average annual output of its two existing hydro stations (6 100 GWh) is equivalent to about 58% of Ghana's technically exploitable hydro capability.

Guinea

Guinea is well-endowed with water resources, having 1 165 watercourses draining into 23 hydrographic basins, of which 16 are shared with neighbouring countries. The WEC Member Committee reports that the gross theoretical hydro capability has been assessed as 26 000 GWh/yr, the technically exploitable capability as 19 300 GWh/yr and the economically exploitable capability as 19 000 GWh/yr. With a current installed hydro capacity of 129 MW and a 2005 output of 445 GWh, it is clear that the republic's potential has barely been touched – less than 3% of the economic capability has been harnessed so far.

The capacity potential corresponding to the technically exploitable capability of 19 300 GWh/yr is 6 100 MW, located mainly in the regions of Basse Guinée (46%) and Moyenne Guinée (43%), with minor amounts in Haute Guinée (8%) and Guinée Forestière (3%). Some 40% of the national hydro potential lies in the basin of the River Konkouré.

The Guinea Member Committee reports that there were no hydro plants actually under construction at end-2005 but that 836 MW, with a probably annual generation of 3 940 GWh, was under study. Additional hydro output which might feasibly become available in the longer term is put at over 5 100 GWh/yr. Taken together with the planned development of hydro capacity, this would imply an eventual total output of some 9 500 GWh/yr, equivalent to 50% of the assessed economically exploitable capability.

The 836 MW reported as planned, consisting of Fomi (90 MW), Souapiti (508 MW) and Kaléta (238 MW), is stated by *Hydropower & Dams World Atlas 2006* to be under construction (as at early 2006).

Guinea's technically exploitable small-scale hydro potential is reported to be 1 224 GWh/yr. Total installed capacity in this category was just under 11 MW at end-2005, producing an output of 29 GWh in a normal year (generation in 2005 was very low, at less than 12 GWh).

Iceland

Apart from its geothermal resources, Iceland's hydropower potential represents virtually its only indigenous source of commercial primary energy. Its gross theoretical potential of 184

TWh/yr includes 40 TWh of economically exploitable output. Hydroelectricity production in 2005 was just over 7 TWh, implying that 17-18% of this economic potential has been developed. Hydropower provided 16% of Iceland's primary energy consumption and 81% of its electricity generation in 2005, but owing to a considerably higher contribution from geothermal power generation, hydro's share fell to 73% in 2006.

The Kárahnjúkar hydro project in eastern Iceland, presently nearing completion, will add 690 MW to the existing installed capacity of 1 160 MW. A further 100 MW of hydro capacity is planned.

The technically exploitable capability of small-scale hydro plants is reported to be 12.3 TWh/yr, equivalent to about 19% of the level for total hydro. Installed capacity of small hydro at end-2005 was 53 MW, or 4.6% of total hydro capacity.

India

India's gross theoretical hydropower potential (2 638 TWh/yr) and technically feasible potential (660 TWh/yr) are amongst the highest in the world. The public utilities' total installed hydroelectric capacity exceeded 32 000 MW at the end of 2005, with a corresponding generation of 97.4 TWh, equivalent to 16% of India's public sector electricity generation.

The Indian WEC Member Committee reports that about 13 GW of hydro capacity was under construction at end-2005 and that a further 9 GW is planned.

The largest hydro plants currently under construction are Subansiri Lower (2 000 MW), Parbati II (800 MW) and Omkareshwar (520 MW). Teesta V (510 MW) is expected to be completed during 2007.

Numerous other hydro projects are under way or at the planning stage. In addition, 55 hydro schemes have been designated as suitable for renovation and upgrading, which could eventually result in an increment of some 2 500 MW to India's generating capacity.

Hydropower & Dams World Atlas reports that there are 420 small-scale hydro plants in operation, with an aggregate installed capacity of about 1 423 MW; a further 521 MW of small-scale capacity is under construction.

Indonesia

At some 2 150 TWh/yr, Indonesia's gross theoretical hydro potential is the third largest in Asia. Its technically exploitable capability is just over 400 TWh/yr, of which about 10% is considered to be economically exploitable. Average annual hydro output is about 9 200 TWh, indicating the evident scope for further development within the feasible potential. Hydro presently provides approximately 12% of Indonesia's electricity supply.

The Indonesian WEC Member Committee reports that 135 MW of hydroelectric generating capacity was under construction at end-2005 and that 802 MW of additional hydro capacity was at the planning stage.

The installed capacity of small-scale hydro plants is reported as 20.89 MW, with 2005 generation amounting to 55.71 GWh. Additional capacity of 17.31 MW is on order or planned.

Italy

Italy's theoretical resource base for hydropower is one of the largest in Western Europe, and its economically exploitable capability is nearly as much as that of France. Hydroelectric power has not, however, been developed to quite the same degree as in the case of its neighbour: about 72% of the assessed economic potential of 65 000 GWh/yr has so far been harnessed. Hydroelectricity accounts for about 19% of Italy's power generation.

The installed capacity of small-scale plants at end-2005 was 2 405 MW, representing about 14% of the overall hydro capacity of 17 326 MW. About 21% of the overall hydroelectric generation is attributable to small-scale plants. The Italian WEC Member Committee reports that the hydro potential for small-scale plants has been largely tapped; current efforts are concentrated on the extension, revamping and return to operation of existing schemes, fuelled by the appropriate incentives.

Hydro power plants are eligible for:

- mandatory national quotas and tradable green certificates (TGC) (currently, TGC value is € 109 + power market price of around € 60/MWh);
- RECs (renewable energy certificates) TGC and Guarantee of Origin (GO) for voluntary support;
- dispatching priority.

Some HPPs are still supported under the former (expiring) feed-in tariffs.

Japan

A high proportion of Japan's large potential for hydro generation has already been harnessed. *Hydropower & Dams World Atlas 2006* (HDWA) quotes its gross theoretical capability as about 718 TWh/yr, of which 136 TWh is regarded as technically exploitable and 114 TWh as economically exploitable. Hydro generation (including pumped storage output) amounted to some 86.5 TWh, representing nearly 8.5% of Japan's electricity.

The Japanese WEC Member Committee reports that 745 MW of conventional hydro capacity was under construction in 2005. Most of the sites suitable for the installation of large-scale conventional hydroelectric plants have now been developed. The great majority of the larger hydro projects presently under construction or planned in Japan are pumped-storage schemes. HDWA reported that 7 520 MW of pumped-storage was under construction.

The technically exploitable capability for small-scale hydro developments is reported by the Japanese Member Committee to be 47 TWh/yr, a relatively high proportion (34%) of the total hydro level. Developed small-hydro capacity at end-2005 was about 3.5 GW, equivalent to 12.5% of total hydro capacity. Capacity planned for construction totalled 106 MW, with a probable annual generation of 478 GWh.

Jordan

The Jordanian WEC Member Committee reports that pre-feasibility studies have indicated a technical hydro potential of 400-800 MW exploiting the difference in elevation of about 400 metres between the Red Sea and the Dead Sea. Terms of Reference for this project were approved by the three parties concerned (Jordan, Palestine and Israel) during a conference held at the Dead Sea in May 2005.

Conventional hydropower resources in Jordan are limited, owing to the fact that surface water resources are almost negligible at present. There are two small HPPs: the King Talal Dam with a rated capacity of 5 MW and a scheme at Aqaba thermal power station which utilises the available head of returning cooling seawater, also with a capacity of 5 MW. There are no plans for the expansion of conventional hydro capacity.

Latvia

Although its hydro potential is quite modest - a gross theoretical capability of only about 7 TWh/yr - Latvia is of interest for its rapid development of small-scale hydro plants in recent years. Beginning in 1992, after Latvia had regained its independence, a period of reconstruction and building of small hydropower stations ensued. This was stimulated mainly by the regulations adopted by the Government on the purchase of electric energy produced in small power plants which, in effect, subsidised the production of electric energy in such stations. In 1996 there were only 16 small hydro stations, which generated 4.5 GWh. By 1999, the number in service had grown to 53 and annual generation to 15 GWh. By 2005, the number in service was 140 and annual generation 61 GWh.

The total gross generating capacity of Latvia's existing hydro power plants is 1 561 MW, comprised of the following:

Plant	Capacity (MW)	Number of units /plants
Plavinas HPP	869	10 units
Kegums HPP-1	72	4 units
Kegums HPP-2	192	3 units
Riga HPP	402	6 units
Small hydro	26	149 plants
Total	**1 561**	

The Latvian WEC Member Committee notes that new (and not yet approved) Regulations of the Cabinet of Ministers on support of renewable energy (RES-E) sources assume the following utilisation of hydropower up to 2010:

	2007	2008	2009	2010
Large hydro > 5 MW				
Share in energy balance, %	41.28	39.21	37.25	35.39

Annual generation, GWh	2 740	2 740	2 740	2 740
Capacity, MW	1 535	1 535	1 535	1 535
Small hydro < 5 MW				
Share in energy balance, %	1.04	1.26	1.47	1.64
Annual generation, GWh	68	87	107	125
Capacity, MW	27	35	43	50

The guidelines for the utilisation of RES-E estimate the overall economic potential of small hydro power plants up to 2025 as in the range of 150 to 300 GWh per year.

Energy development forecasts of the Latvian power system to 2025 consider the possible construction of new hydro power plants on the river Daugava: Daugavpils HPP (100 MW) and Jekabpils HPP (30 MW).

Lithuania

The Lithuanian WEC Member Committee reports that at present the construction of large-scale hydro power plants is not contemplated, owing to environmental and other restrictions.

The planned capacity of small-scale HPPs to be constructed by 2010 is about 6 MW. The Government has approved a regulation (No. 1 474: Procedure for the Purchasing of Electricity Generated from Renewable and Waste Energy Sources). According to this regulation, generation is promoted in small-scale HPPs, and feed-in tariffs (€ 0.0579/kWh) are applied to the purchase of electricity generated by such power plants.

Madagascar

Madagascar has a considerable land area (greater than that of France, for example) and heavy annual rainfall (up to 3 600 mm). Consequently, the potential for hydropower is correspondingly large: gross theoretical potential is put at 321 TWh/yr, within which the technically feasible potential is 180 TWh/yr. With current installed capacity standing at 105 MW and annual hydro output about 540 GWh, the island's hydro capability has scarcely begun to be utilised.

There are two HPPs of over 10 MW capacity: Mandraka (24 MW) and Andekaleka (58 MW). Financing has been arranged for an additional 29 MW unit at Andekaleka, while two small hydro plants are under construction at Sahanivotry (12 MW) and Lily (3.5 MW), with all three expected to be completed during 2007-2008.

Malaysia

There is a substantial potential for hydro development, with a total technically feasible potential of about 123 TWh/yr, most of which is located in Sarawak (87 TWh/yr) and Sabah (20 TWh/yr); a considerable proportion of Peninsular Malaysia's technically feasible potential of 16 TWh/yr has already been developed.

After being halted in 1997 as an austerity measure, construction of the 2 400 MW Bakun hydro project in Sarawak is once again under way. There is also a 300 MW hydro plant planned for construction at Ulu Terengganu, Peninsular Malaysia and a 210 MW scheme at Sungai and Pelus.

Mexico

With a gross theoretical hydro capability of 135 TWh/yr and a technically exploitable capability of 49 TWh/yr, Mexico possesses a considerable hydroelectric potential. Its economically exploitable capability is 32.2 TWh/yr.

A major extension of the Manuel Moreño Torres (Chicoasén) hydro plant, involving three new units with a total incremental capacity of 900 MW, was completed in 2004. The commissioning of several smaller HPPs (each with capacities of less than 30 MW) added a further 39 MW, whilst 17 MW of hydro capacity was decommissioned, resulting in a net addition of 922 MW to Mexico's hydro generating capacity.

The 754 MW El Cajón plant, reported as under construction at end-2005, has subsequently entered operation. More than 2 000 MW was stated to be planned for future development. The plants involved were new hydro stations at La Parota (900 MW) and La Yesca (750 MW) and an extension of La Villita (400 MW).

At end-2005, installed capacity of small-scale hydropower is reported by the Mexican WEC Member Committee to have been 109 MW, with output during the year 479 GWh.

Myanmar

The country is well endowed with hydro resources: its technically feasible potential is given by *Hydropower & Dams World Atlas 2006* as 37 000 MW. At an assumed annual capacity factor of 0.40, this level would imply an annual output capability of approximately 130 TWh; actual output in 2005 was only 3.0 TWh. There thus appears to be ample scope for substantial development of hydropower in the long term.

Current hydro capacity is about 745 MW, but plants under construction will substantially increase this total within a few years. Twelve hydro plants, with a total capacity of 1 786 MW, were reported to be under construction at end-2005. The major stations involved were a 400 MW plant on the Shweli river in northeast Myanmar, due for completion in June 2007, and Yeywa (790 MW) on the Myitnge towards the centre of the country, scheduled to come into service in June 2008. Longer-term projects under consideration include a major export-orientated scheme, Ta Sang (7 110 MW), from which it is planned to export 1 500 MW to Thailand by 2010.

Namibia

Namibia's only perennial rivers are the Kunene and Kavango (forming borders with Angola and Zambia in the north) and the Orange River bordering South Africa in the south. The Namibian WEC Member Committee notes that any plans to develop hydro power are thus subject to lengthy bilateral negotiations. Another problem leading to limited exploitation of hydro resources is the scarcity of rain and the extensive droughts.

Little has been done in Namibia with regard to the development of small hydro power plants. Small hydro potential can be found mostly on the Kavango and Orange Rivers, since the Kunene is situated in a remote area. The waters of the Orange River are dedicated to irrigation projects and mining activities.

Nepal

There is a huge theoretical potential for hydropower, reported by *Hydropower & Dams World Atlas 2006* (HDWA) to be some 733 TWh/yr, with a technically exploitable capability put at 43 000 MW (corresponding to an output of about 151 TWh/yr, assuming a capacity factor of 0.40). The HDWA quotes Nepal's economically exploitable capability as 14 742 GWh/yr – a much lower level than that reported by the Nepalese WEC Member Committee for the 2004 *Survey.*

Total hydro capacity at end-2005 was 560 MW, with a further 69 MW of capacity under construction, all of which was scheduled for completion by the end of 2007. Actual hydro generation in 2005 was 2 511 GWh, a small fraction of even the lower economic potential quoted above.

HDWA reports that there are 42 small and mini hydro schemes in operation, with an aggregate capacity of very nearly 20 MW. Additional small plants under construction or planned for installation in the near term total some 30 MW.

Nepal's topography gives it enormous scope for the development of hydroelectricity, which probably provides the only realistic basis for its further economic development. Small-scale hydro plants are the most viable option for rural electrification. Large projects, however, in view of Nepal's limited financial resources, would probably require power export contracts with India as a prerequisite.

Norway

Norway possesses Western Europe's largest hydro resources, both in terms of its current installed capacity and of its economically feasible potential. *Hydropower & Dams World Atlas 2006* reported a gross theoretical capability of 560 TWh/yr, of which 187 TWh was economically exploitable. The hydro generating capacity installed by the end of 2005 had an output capability equivalent to about two-thirds of the economic potential. Actual hydro output in 2005 was around 136 000 TWh, providing virtually all of Norway's electric power.

Two major HPPs were under construction at end-2005: Nit Tying (168 MW) and Over Otta (171 MW). A further 859 MW was licenced for development.

The economically exploitable capability applicable to small-scale hydro schemes was reported to be 9 TWh/yr, equivalent to 5% of the overall level. Installed capacity of small hydro plants totalled about 1 000 MW at end-2005 with an average annual output capability of 5 TWh.

Pakistan

At 30 June 2006, total installed hydro capacity was 6 499 MW, almost exactly one-third of total national generating capacity. According to *Hydropower & Dams World Atlas 2006* (HDWA), Pakistan has a gross theoretical hydro potential of approximately 480 TWh/yr, of which some 219 TWh/yr is regarded as technically feasible. The main potential sources of hydropower are on the rivers Indus and Jhelum, plus sites at Swat and Chitral. Both hydro and thermal power plants are being developed to meet the country's demand for electricity, as part of the state utility WAPDA's Vision 2025 programme.

Hydro capacity in operation at the end of 2005 included major plants at Tarbela (3 478 MW) and Mangla (1 000 MW); output during the year was 25.7 TWh, accounting for 29% of Pakistan's electricity generation. Capacity reported to be under construction at end-2005 amounted to 875 MW, the major project being the heightening of the dam at the Mangla HPP, which will raise its capacity by 180 MW. Many other sites have been identified for development in the medium and longer term: the total capacity reported as planned ranges from 8 100 MW to as much as 27 000 MW, if numerous public and private sector projects were eventually to come to fruition.

HDWA quoted Pakistan's small-scale (1-22 MW) hydro potential as 434 GWh/yr, but said that only 68 out of an installed capacity of 107 MW was actually in operation. A total of 550 MW of small hydro capacity was reported to be planned.

Paraguay

In the context of energy supply, Paraguay's outstanding natural asset is its hydroelectric potential, which is mainly derived from the river Paraná and its tributaries. The country's gross theoretical capability for hydroelectricity is about 130 TWh/yr, of which 101 TWh is estimated to be economically exploitable. Two huge hydroelectric schemes currently utilise the flow of the Paraná: Itaipú, which Paraguay shares with Brazil, and Yacyretá, which it shares with Argentina.

Itaipú is the world's largest hydroelectric plant, with a total generating capacity of 12 600 MW at end-2005, of which Paraguay's share was 6 300 MW. This share is far in excess of its present or foreseeable needs and consequently the greater part of the output accruing to Paraguay is sold back to Brazil. Itaipú's 19th 700 MW unit entered commercial operation in September 2006, bringing total capacity at the site up to 13 300 MW. The 20th 700 MW generator is expected to come on line during 2007. Electricity generation at Itaipú in 2006 totalled 92 690 GWh.

The bi-national plant at Yacyretá, downstream from Itaipú, has an installed capacity of 3 100 MW. There are 20 generating units, each of 155 MW capacity, but all are still operating at only 90 MW per unit, owing to the level of the reservoir being held below that originally planned.

Paraguay has a wholly-owned 210 MW hydro plant (Acaray), which will probably be uprated by 45 MW during the next few years. The state electric utility, ANDE, also plans to install two 100 MW units at Yguazu. An environmental impact study has been conducted for the projected bi-national Corpus Christi dam (2 880 MW, to be shared with Argentina), sited on the Paraná, downstream of Itaipú and upstream of Yacyretá.

Peru

Peru's topography, with the Andes running the length of the country, and many fast-flowing rivers, endows the republic with an enormous hydroelectric potential. Its hydro capability is assessed as one of the largest in the whole of South America: its economically exploitable capability is some 260 TWh/yr. Current utilisation of this capability is very low - at around 7%. Hydro provides about 72% of Peru's electric power.

The Peruvian WEC Member Committee reports that at end-2005 one medium-sized HPP was under construction: El Platanal (220 MW). It also notes that 1 079 MW of additional hydro capacity is planned, including Machu Picchu (71 MW) and Pucara (130 MW).

Small-scale hydro plants had an aggregate capacity of 228 MW at end-2005, and generated 1 002 GWh during the year. A small (10 MW) HPP is under construction at La Joya, which is expected to come into operation in 2008. The Rural Electrification Plan 2005-2014 foresees the installation of 28 mini-hydro plants, with an aggregate capacity of 7.229 MW, during the period to 2014. Laws approved by the Peruvian authorities in 2006 specified that renewable indigenous energy resources, including hydropower, should be accorded priority in rural electrification schemes, and that distributed generation sources linked to the national interconnected electrical system (SEIN) should have use of the distribution network, paying only the incremental cost incurred.

Russian Federation

Russia's hydro resource base is enormous - the gross theoretical potential is some 2 295 TWh/yr, of which 852 TWh is regarded as economically feasible. The bulk of the Federation's potential is in its Asian regions (Siberia and the Far East). Hydro generation in 2005 (165 TWh) represented 19% of the economic potential and accounted for about 18% of total electricity generation.

At the end of 2005 installed hydroelectric generating capacity was about 45 700 MW, according to the Russian WEC Member Committee; 5 648 MW of additional capacity was under construction and 8 000 MW of further capacity was planned for installation.

Two plants under construction were in partial operation at end-2005: Bureiskaya on the River Bureya in the Russian Far East, with 670 MW in use and Irganaiskaya in Dagestan, southern North Caucasus, with 214 MW. The planned capacities of these two plants on completion are 2 000 MW and 800 MW, respectively.

Large hydro: >10 MW

Name of potential hydro-electric site (river)	Province and water management area	Estimated parameters			Installed capacity (MW)	Estimated output (GWh)
		Average head (m)	Flow rate (m^3/s)	Load factor (%)		
Laleni Dam (Tsitsa)	Eastern Cape	70	25	30	44	116
Tsitsa Falls (Tsitsa)	Eastern Cape	250	25	30	150	394
Mpindeni & Ku-Mdyobe dams plus 4 diversion weirs (Tina)	Eastern Cape	83	18	30	210	552
Bokpoort & Luzi dams plus 2 diversion weirs (Mzintlava)	Eastern Cape	91	10	30	56	147
Ntlabeni & Sigingeni Dams (Upper Mzimvubu)	Eastern Cape	22	33	30	340	894
Mbokazi Dam (Lower Mzimvubu)	Eastern Cape	200	95	30	450	1 183
Thukela, Usutu and Mhlathuze	KwaZulu-Natal				3 721	9 790
Upper Orange	Northern Cape				120	525
Estimated macro hydro-electric potential					**5 091**	**13 601**

The other hydro plants under construction comprised:

- Boguchanskaya (1 920 MW, eventually rising to 3 000 MW) on the Angara river in southeast Siberia;
- Zelenchukskie HPPs (320 MW) in Karachai-Circassia, North Caucasus;
- Zaramagskie HPPs (352 MW) in North Ossetia, North Caucasus;
- Nizhne-Cherekskie HPPs (Sovetskaya HPP) (60 MW) in Kabardino-Balkaria, North Caucasus.

South Africa

The South African WEC Member Committee has provided the following information on the republic's hydro resources (courtesy of Eskom):

Small scale hydro: <10 MW

Province	Installed capacity (MW)	Firm development potential (MW)
Northern Cape		
Western Cape	1.8	3.2
Eastern Cape	14.7	19.5
Free State	0.3	10.5
North West		
KwaZulu-Natal	0.1	5.0
Mpumalanga	16.4	12.7
Gauteng		
Limpopo	0.6	18.1
Total	**33.9**	**69.0**

The R&D aspects of pico/micro/mini and small hydropower technology applications are at present vested primarily in the private sector. A handful of individuals are investing their time and expertise in micro-hydropower research. There are no particular incentives being offered to promote R&D and education in hydropower.

Spain

In terms of hydro-electric resources, Spain stands in the middle rank of West European countries, with a gross theoretical capability of about 150 TWh/yr. Along with this level, the Spanish WEC Member Committee reports that some 65 600 GWh/yr is considered to be technically exploitable, of which 31 600 (48%) is classed as economically exploitable at present. The level of hydro-electricity generation in 2005 (23 215 GWh) indicates that Spain has already harnessed a considerable proportion of its economic hydro resources.

Provisional data for end-2005 show that small-scale HPPs had a total generating capacity of 1 788 MW, and that their output in 2004 was 4 729 GWh. During the period 2005-2010 some 450 MW of small hydro capacity is scheduled to be added, eventually providing incremental output of around 1 271 GWh/yr.

Sweden

Sweden has one of the highest hydro potentials in Western Europe: the Swedish WEC Member Committee reports a gross theoretical capability of 130 TWh/yr, of which 85 TWh is economically exploitable. The average annual capability of the 16 100 MW hydro capacity installed at the end of 2005 was 65 TWh, about 76% of the economic potential. Actual hydro output in 2005 was 72 TWh, which provided nearly half of Sweden's electricity generation. The construction of new hydro plants has virtually stopped, on account of environmental and political considerations. Future activity is likely to be very largely confined to the modernisation and refurbishment of existing capacity.

There is 985 MW of small-scale hydro capacity installed, which generated a total of 3.8 TWh in 2005.

Tajikistan

The terrain and climate are highly favourable to the development of hydropower. Apart from the Russian Federation, Tajikistan has the highest potential hydro generation of any of the FSU republics. Its economically feasible potential is estimated to be 263.5 TWh/yr, of which only about 6% has been harnessed so far. Hydropower provides over 95% of Tajikistan's electricity generation.

Just over 4.5 GW of hydro capacity is installed, the principal site being Nurek (3 000 MW). The Sangtuda plant, currently under construction, will add another 670 MW to Tajikistan's capacity. *Hydropower & Dams World Atlas 2006* reports that an enormous hydro potential exists on the river Panj (the principal tributary of the Amu-Darya): 14 HPPs with an aggregate capacity of 18 720 MW could eventually be developed. (As the Panj forms Tajikistan’s border with Afghanistan, a portion of the capacity/output would presumably accrue to the latter country). Additional potential capacity of around 4 800 MW could be installed at sites on other rivers, for which feasibility studies have been conducted. Lastly, work on the huge Rogun scheme (3 600 MW) on the river Vakhsh has been suspended, but is expected to go ahead in due course. If all these potential developments came to fruition, as much as 27 000 MW might be added to Tajikistan's hydro generating capacity over the long term.

Turkey

The Turkish WEC Member Committee reports a gross theoretical hydropower potential of 433 TWh/yr, a technically feasible potential of 216 TWh/yr and an economically feasible potential of almost 130 TWh/yr. Hydro output of 35.1 TWh in 2005 points to a considerable degree of development potential.

At end-2005, operational hydro capacity amounted to almost 12.8 MW. A further 3.2 GW of capacity was under construction at that point in time. Some 20 000 MW of additional capacity is planned for development over the longer term.

Small-scale hydropower is reported to have a technically exploitable capability of around 14 500 GWh/yr, of which about 60% is considered to be economic. The total installed capacity of HPPs below 10 MW was 173 MW at end-2005, providing an average output of 675 GWh. A considerable amount of small-scale hydro capacity (over 1 000 MW) is planned for installation in the future.

Ukraine

The Ukrainian WEC Member Committee reports that the completion of the construction of hydro pumped-storage capacity of 4 074 MW and the building of hydro power plants on the rivers Tysa, Dnistr and their run-offs, are planned for completion within 5-10 years.

It is also planned to reconstruct the small hydro power stations in use, to rehabilitate stations that are out of operation and, after 2010, to build new stations on small rivers (using the existing reservoirs within the water supply and water removal systems).

United Kingdom

While the overall amount of installed hydro-electric capacity is extremely modest, opportunities for development do exist, especially in the small-hydro sector (defined in this context as plants up to 5 MW). *Hydropower & Dams World Atlas 2006* quotes the technically feasible potential for small hydro so defined as 4 577 GWh/yr, with the economically feasible potential for undeveloped sites as 1 100 GWh/yr.

The British Hydropower Association, as quoted by the United Kingdom WEC Member Committee, believes that there is the potential to double, or possibly triple, existing capacity, i.e. an additional generating capacity of 1 300-2 600 MW. Some 300-500 MW would be in large hydropower plants, with the balance in small, mostly run-of-river, plants. There are many former water-mill sites and utility and river structures that offer potential for small hydro developments.

A possible pointer to future developments lies in the fact that construction work has started on the 100 MW Glendoe scheme in Scotland – the first sizeable conventional hydro plant to be built in the UK for almost fifty years.

The Renewables Obligation requires licensed electricity suppliers to source a specific and annually increasing percentage of the electricity they supply from renewable sources. The current target is 6.7% for 2006/07 rising to 15.4% by 2015/16. Eligible sources include new hydro and refurbished hydro (up to 20 MW).

United States of America

The hydro resource base is huge: the gross theoretical potential was assessed in 1979 as 512 GW, equivalent to 4 485 TWh/yr. The United States WEC Member Committee has reported that the annual technically exploitable capability is 1 752 TWh, of which 501 TWh is economically exploitable, both based on publications of the Idaho National Environmental and Engineering Laboratory. The end-2005 US hydro capacity of 77.4 GW had an average annual capability of about 292 TWh, equivalent to 58% of the assessed economic potential.

Actual hydroelectric output of 269.6 TWh in 2005 accounted for 6.7% of US electricity generation. Only 8 MW of hydro capacity was under construction at end-2005, and 16 MW was at the planning stage.

The reported technically exploitable capability of small-scale hydropower is almost 584 TWh. The installed generating capacity of small hydro plants totalled 2.84 GW at end-2005; actual generation in 2005 was about 10.7 TWh, equivalent to 4% of total US hydro output.

Uruguay

Hydropower is Uruguay's only indigenous source of commercial primary energy, but even this is on a relatively limited scale. According to *Hydropower & Dams World Atlas 2006*, the technically exploitable potential is 10 TWh/yr, within a gross theoretical potential of 32 TWh, none of which is regarded as economically feasible for development at present.

During the 1980s almost all of Uruguay's incremental generating capacity was in the form of hydropower, notably through the commissioning of the bi-national Salto Grande (1 890 MW) plant on the river Uruguay; the republic shares its output with Argentina. No hydro plants are reported to be presently under construction or planned: future increases in generating capacity are likely to be largely fuelled by natural gas.

The Government passed a decree in March 2006 which, as a first stage, attempts to encourage the installation of up to 20 MW of electricity generation based on small-scale hydropower (under 10 MW) provided by IPPs. The Uruguayan WEC Member Committee estimates that taking into account schemes of less than 5 MW (totalling 203 MW) and a theoretical capacity factor of 0.5, the technically exploitable capability would be 889 GWh/yr.

Venezuela

The Venezuelan WEC Member Committee reports a gross theoretical capability of 320 TWh/yr, of which 130 TWh/yr is considered as economically exploitable. Hydro-electric output in 2005 was 77.2 TWh, about 4% below the level reported for probable annual generation. Hydro output in an average year would be 80.6 TWh, indicating that not far short of two-thirds of the realistic potential has already been harnessed. About 74% of the republic's electricity requirements are met from hydropower.

A large increase in hydro-electric capacity occurred during the 1980s, the major new plant being Guri (Raúl Leoni), on the river Caroní in eastern Venezuela - its capacity of 10 000 MW makes it one of the world's largest hydro stations.

At the end of 2005, total hydro-electric generating capacity is reported to have been approximately 14.4 GW; 2.25 GW was under construction and a further 3 GW of hydro capacity was planned for future development.

The 2 160 MW Caruachi project, sited 59 km downstream from Guri, was scheduled for phased entry into operation between 2003 and 2006. The last major hydro project planned for the lower river Caroní is Tocoma (2 160 MW), scheduled for completion by 2014. Eventually, the total installed capacity on the lower Caroní (comprising, in order of flow, Guri, Tocoma, Caroní and Macagua (2 930 MW)) will exceed 17 000 MW.

The installed capacity of small-scale HPPs is quite modest: a mere 1.59 MW at end-2005, producing just under 7 GWh in a 'normal' year and an actual 3.4 GWh in 2005. There are orders or plans for an additional 5.1 MW in this category.

Vietnam

Vietnam has abundant hydro resources, particularly in its central and northern regions. Its gross theoretical potential is put at 300 000 GWh/yr, with an economically feasible potential of 75-80 000 GWh/yr. Total installed hydro capacity was nearly 4 200 MW in 2005 and an output of about 18 TWh provided about one-third of Vietnam's power supply. The largest HPPs currently in operation in Vietnam are Hoa Binh (1 920 MW), Yali (720 MW), Tri An (400 MW) and Ham Thuan (300 MW).

Hydropower & Dams World Atlas 2006 (HDWA) reported that a major programme of hydropower development was under way by end-2005, with 20 plants totalling 6 768 MW being constructed for the state corporation EVN, and a further 1 000 MW being built by private developers under BOT or IPP arrangements. Other large amounts of hydro capacity totalling around 4 600 MW, were reported to be under planning.

HDWA also reported that there were 300 small/mini HPPs (up to 30 MW) in operation, total capacity in this category being some 50 MW. A 20 MW plant was under construction at Huong Dien on the river Bo, whilst four small HPP projects, with an aggregate capacity of 56.5 MW, were at the planning stage.

8. Peat

COMMENTARY

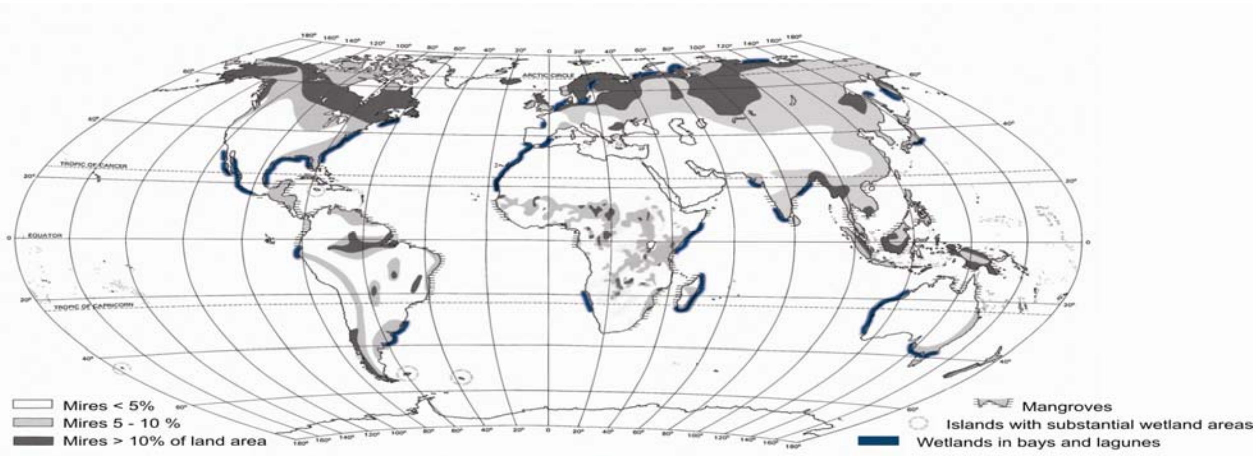
Introduction

Peat is a soft organic material consisting of partly decayed plant matter together with deposited minerals. Table 8-1 indicates for each country the area covered by a layer of peat, known as peatland. For land to be designated as peatland, the depth of the peat layer, excluding the thickness of the plant layer, must be at least 20 cm on drained land, and 30 cm on undrained. Peatland reserves are most frequently quoted on an area basis because initial quantification normally arises through soil survey programmes or via remotely-sensed data. Even where deposit depths and total peat volumes are known, it is still not possible to quantify the reserves in energy terms because the energy content of in-situ peat depends on its moisture and ash content. However, the organic component of peat deposits has a fairly constant anhydrous, ash-free calorific value of 20-22 MJ/kg, and if the total quantity of organic material is known, together with the average moisture and ash content, then the peat reserve can be expressed in standard energy units.

Resources

Whilst the measurement of peat resources on a global scale is difficult, with data for many countries being imprecise or only partially ascertained, it is clear that the world possesses a huge tonnage of peat overall. The total area of peatland, based on reports from WEC Member Committees and published sources (notably,

Figure 8-1 Distribution of mires
Source: International Peat Society



Lappalainen, 1996), comes to over 2.7 million km^2 or about 2% of the world's land surface. A considerable proportion of the world's peatlands is located in North America and the northern parts of Asia; significant deposits also occur in northern and central Europe and in Indonesia, whilst further accumulations have been identified in tropical Africa, Latin America and southern/eastern Asia. The average thickness of the peat layer in Europe has been computed as 1.57 metres; information available for other continents indicates that the average depth of the world's peatlands is 1.3-1.4 m (Lappalainen, 1996).

An indicative estimate of the total volume of peat in situ is thus in the order of 3 500 to 4 000 billion m^3. The peat reserve base in major producing countries (covering 'reserves currently under active cultivation or economically recoverable under current market conditions') has been assessed (Couch, 1993) as 5 267 million tonnes (air-dried).

Uses of Peat

Peat has a large number of uses, which may be classified under three headings:

- horticultural and agricultural uses (e.g. as growing medium, soil improver, cowshed/stable litter, compost ingredient);
- energy use (as fuel for electricity/heat generation, and directly as a source of heat for industrial, residential and other purposes);
- other uses (e.g. as a source of organic and chemical products such as activated carbon, resins and waxes, medicinal products such as steroids and antibiotics, and therapeutic applications such as peat baths and preparations).

Production Methods

Peat is either extracted as sods (traditionally hand-cut, nowadays predominantly harvested mechanically) or as fine granules (using a mechanical miller to disturb and granulate the top layer of the peat bog surface).

Peat *in situ* contains around 90% water; some of this is removed by drainage and most of the remainder by drying in the wind/sun. The resulting 'air-dried' peat has a moisture content of 40-50%.

The bulk of peat production is obtained by milling and used in electricity/heat generation. A proportion of the milled peat is converted into briquettes, which provide a convenient household fuel.

Energy Markets

At the present time, the principal producers (and consumers) of fuel peat are Ireland, Finland, Belarus, Russia, Sweden and Ukraine.

Figure 8-2 Greenhouses heated with sod peat
Source: Turveteollisuusliitto

Figure 8-3 Forssan Energia uses both peat and wood-based fuels in combined heat and power production
Source: Turveteollisuusliitto

Total consumption reported for 2004 (IEA, 2006) was 17.3 million tonnes. Recorded production was considerably lower, at around 13.5 million tonnes. The balance of supply came out of stock, a normal feature of the peat supply/demand picture, reflecting the substantial (and unavoidable) year-to-year variations in peat production occasioned by the weather prevailing during the harvesting period.

Peat consumption for energy purposes outside Europe is essentially negligible at present. The sectoral breakdown in Europe (including all of the Russian Federation) in 2004 was: power stations, CHP and heat plants 69%, input to briquetting plants 15%, residential use 8%, industry 6% and other users 2%.

Peat from a Climate Impact Point of View

The question of whether or not peat is a fossil or a renewable fuel was studied comprehensively, and probably for the first time, in 2000 when scientists proposed that peat should be referred to as a 'slowly renewable fuel' (Crill, Hargreaves and Korhola, 2000). Since then, several new studies have been carried out, none of which has defined peat as a fossil fuel. The latest, by the Intergovernmental Panel on Climate Change (IPCC) changed the classification of peat from fossil fuel to a separate category between fossil and renewable fuels (25^{th} session of IPCC, Port Louis, Mauritius, 2006). Peat now has its own category: 'peat'. It should be mentioned that the latest life-cycle studies referred to in this commentary were not considered by the IPCC because they were completed after its 25th session.

The Nature of Peatlands and Peat

Globally, peatlands are major stores of carbon. Peatlands are also vital environmental 'regulators'. Peat is accumulating on the ground all the time and the top layers of mires and peatlands form complex ecosystems.

Joosten and Clarke (2002) describe peatlands as analogous to living organisms because they grow, mature and may even die. Joosten and Clarke continue: peat is 'sedentarily accumulated material consisting of at least 30% (dry weight) of dead organic material'.

Peat is the partly decomposed remains of the biomass that was produced, mostly by plants, on waterlogged substrates; it is mostly water-saturated and therefore not compacted. The peat harvested today in the northern hemisphere was formed during the Holocene epoch (the last 10 000 years), after the retreat of the glaciers that once covered most parts of Europe. Those parent plant species, which formed the basal peat, are still forming peat today.

Peat used for fuel consists of different peat layers of different ages. The above-peat biomass (sedges, mosses, shrubs and trees), which is milled and mixed with the upper peat layer in the preparation of the production field, also contains the material freshly grown during the summer before milling. The surface part of peat below the living ground layer, being less than 300 years old, amounts on average to 10.2% of the total peat carbon volume (Mäkilä, 2006). Only the deeper and basal parts of the peat are thousands of years old.

Figure 8-4 A 25-40 mm thick layer of peat is milled from the surface of the peat production site. The milled peat will be dried by the sun. Since solar energy is used in the drying process, peat production must take place in dry weather
Source: Turveteollisuusliitto

Figure 8-5 After milling, peat is turned 3-5 times during the next couple of days to improve the drying process
Source: Turveteollisuusliitto

The harvested material thus consists of the living biomass above and below ground, the less-than-300 year old surface layer, which is comparable to wood biomass, (Mäkilä, 2006) and older middle and basal peat. This means that, on average, at least 10% of each peat fuel load consists of very young peat which, according to current criteria, is renewable biomass. This shows that peat is akin to biomass fuels and much closer to them than fossil fuels.

Balance of Peat Usage and Life-Cycle Analysis

The total area of peatlands in Europe is estimated to be 514 882 km^2. Agriculture has been the main user of peatlands, with an estimated 125 000 km^2 of peatlands used from ancient times. Forestry is the second largest user (Joosten and Clarke, 2002). The total production area for fuel peat in the EU amounts to 1 750 km^2 (0.34% of the total peatland area). The total annual use of energy peat has amounted to 12 million delivered tonnes of peat (4 million tonnes of carbon) during recent years (Paappanen, Leinonen and Hillebrand, 2006).

The world's annual peat harvest is equivalent, according to Joosten and Clarke (2002), to about 15 million tonnes of carbon. The present sequestration rate of carbon in all mires of the globe is estimated to be 40-70 million tonnes annually (Joosten and Clarke, 2002), thus exceeding the annual use of peat 3 to 6 times. Peat extraction and peat accumulation are in balance.

A target for further research is how much peat is lost through decomposition on peatlands converted to agriculture and forestry. This is a unique question and every country differs from all others. Finland can be taken as an example: the Geological Survey of Finland studied Finnish peat reserves and found that the country's peat resources in the year 2000 equalled those of 1950, despite widespread use for agriculture and forestry in the intervening period (Turunen, 2004). Furthermore, Finland is a leading country in the industrial use of peat and its peatlands have also been used for the construction of water reservoirs and as a basis for road infrastructure. In spite of such use, Finland's peat carbon stocks are in balance.

Many peatlands in Europe, which were drained and used for agriculture and forestry in the past, are now sources of greenhouse gases, owing to degradation and oxidation of the unsaturated peat layer. If these areas are not significant sources of food or other income for local people, they could be used for peat production and afterwards transformed relatively easily into carbon sinks. This could be done by restoring them to peat-forming mires, by reclaiming them as forests or by planting energy crops. These types of carbon sink will be needed in coming decades. The possibility of reusing energy peat production sites as new carbon sinks constitutes another difference between peatlands and fossil-fuel producing coal mines and oil wells. This difference is clearly shown in life-cycle analyses.

The concept of life-cycle analysis has been used to compare the climate impact of the use of peat as fuel, starting from various peatland types and ending the cycle with different after-use alternatives. A recent report by the VTT Technical Research Centre of Finland (Kirkinen, Hillebrand and Savolainen, 2007) concludes that the climate impact of peat per energy unit is, over a 300 years' perspective, about 10% of the impact of coal, if the peat is produced from former agricultural areas, and rather more than half the impact of coal, if peat is produced from fertile areas drained for forestry. Similar and even lower climate impact is reported by Holmgren and Zetterberg (2005).

Wise Use of Peat

The International Peat Society (IPS) has combined with the International Mire Conservation Group (IMCG) to develop a procedure for the reasoned and wise use of peat and peatlands globally (Joosten and Clarke, 2002). This contains sound advice for the peat industry which, in turn, should follow the 'wise use' approach. This means that most of the remaining peat bogs in Europe will not be utilised by the peat industry (less than 0.4% of the total peatland area in Europe is currently used in this way) and those that are will have after-use plans, to be implemented at the industry's expense once the extraction work has ended. In most cases, former extraction sites are destined to become CO_2 sinks once again.

In conclusion, in order to put CO_2 emissions into context, it is important to emphasise that most of the carbon released from peatland in the world today occurs in tropical Southeast Asia. In 1997, between 0.87 and 2.57 billion tonnes of carbon (equivalent to 2.9-8.5 billion tonnes CO_2) were discharged into the atmosphere as a result of forest and peat fires in Indonesia in just 4 months (Page, et al. 2002). In the 10 years since then, it is estimated that an average of around 2 billion tonnes of CO_2 has been released every year from peatland in Southeast Asia, as a result of peatland deforestation, drainage, degradation and fire. This is equivalent to about 30% of global CO_2 emissions from fossil fuels (Hooijer, et al., 2006). Developed countries should focus in particular on the wise use of tropical peatlands in agriculture and forestry, in order to prevent thoughtless release of CO_2 into the atmosphere.

The IPS is of the view that from a climate-impact point of view peat is much more acceptable than fossil fuels and that peat can be used in a wise way for the benefit of mankind now and in the future.

Jaakko Silpola
International Peat Society

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DEFINITIONS

Types of Peat Fuel

There are three main forms in which peat is used as a fuel:

- **Sod peat** - slabs of peat, cut by hand or by machine, and dried in the air; mostly used as a household fuel;
- **Milled peat** - granulated peat, produced on a large scale by special machines; used either as a power station fuel or as raw material for briquettes;
- **Peat briquettes** - small blocks of dried, highly compressed peat; used mainly as a household fuel.

TABLES

Table 8-1 Peat: areas of peatland

	thousand hectares
Algeria	22
Angola	10
Burundi	14
Congo (Brazzaville)	290
Congo (Democratic Rep.)	40
Côte d'Ivoire	32
Egypt (Arab Rep.)	46
Guinea	525
Kenya	160
Liberia	40
Madagascar	197
Malawi	91
Mozambique	10
Nigeria	700
Rwanda	80
Senegal	7
South Africa	950
Sudan	100
Tunisia	1
Uganda	1 420
Zambia	1 106
Total Africa	**5 841**
Belize	90
Canada	111 328
Costa Rica	37
Cuba	658
El Salvador	9
Haiti	48
Honduras	453
Jamaica	12
Mexico	1 000
Nicaragua	371
Panama	5
Puerto Rico	10
Trinidad & Tobago	1
United States of America	21 400
Total North America	**135 422**
Argentina	50
Bolivia	1
Brazil	1 500
Chile	1 047
Colombia	339
Falkland Islands	1 151
French Guiana	162
Guyana	814
Paraguay	50
Peru	10
Surinam	113
Uruguay	3
Venezuela	1 000
Total South America	**6 240**
Afghanistan	12
Armenia	3
Bangladesh	60
Brunei	10
China	1 044
Georgia	25
India	100
Indonesia	27 000
Japan	200
Korea (Democratic People's Rep.)	136
Korea (Republic)	630
Malaysia	2 536
Myanmar (Burma)	965
Pakistan	2
Philippines	240
Sri Lanka	5
Thailand	64
Turkey	56
Vietnam	100
Total Asia	**33 188**
Albania	10
Austria	22
Belarus	2 397

Table 8-1 Peat: areas of peatland

	thousand hectares
Belgium	20
Bulgaria	3
Czech Republic	27
Denmark	142
Estonia	902
Finland	8 900
France	100
Germany	1 420
Greece	10
Hungary	100
Iceland	1 000
Ireland	1 180
Italy	120
Latvia	640
Lithuania	483
Netherlands	280
Norway	2 370
Poland	1 200
Portugal	20
Romania	7
Russian Federation	56 800
Slovakia	4
Slovenia	100
Spain	38
Sweden	6 400
Switzerland	22
Ukraine	1 008
United Kingdom	1 926
Total Europe	**87 651**
Iran (Islamic Rep.)	290
Iraq	1 790
Israel	5
Total Middle East	**2 085**
Australia	15
Fiji	4
New Zealand	260
Papua New Guinea	685
Total Oceania	**964**
TOTAL WORLD	**271 391**

Notes:

1. Data for African countries are as given by *Global Peat Resources* and relate to total mire areas, which ‘include coastal mangroves and other wetlands without any information about the thickness of peat or other organic soils’.
2. The peatland area shown for Slovenia also includes those in Bosnia-Herzegovina, Croatia, Montenegro and Serbia
3. The peatland area shown for Australia is as reported by the Australian WEC Member Committee for the 1995 *Survey of Energy Resources*; mangrove swamps, tidal marshes and salt flats are excluded
4. Sources: WEC Member Committees; Lappalainen, E. (editor), 1996, *Global Peat Resources*, International Peat Society, Finland

Table 8-2 Peat: 2004 production and consumption for fuel (thousand tonnes)

	production	consumption
Burundi	5	5
Total Africa	**5**	**5**
Falkland Islands	13	13
Total South America	**13**	**13**
Austria	1	1
Belarus	1 993	2 122
Estonia	279	299
Finland	3 200	8 724
Germany	133	11
Ireland	4 395	2 706
Latvia	13	9
Lithuania	50	47
Romania	8	10
Russian Federation	1 487	1 405
Sweden	1 276	1 276
Ukraine	707	653
United Kingdom	20	20
Total Europe	**13 562**	**17 283**
TOTAL WORLD	**13 580**	**17 301**

Notes:

1. Data on production relate to peat produced for energy purposes; data on consumption (including imported peat) similarly relate only to fuel use.
2. Annual production of peat in individual countries tends to vary considerably from year-to-year; the peat drying process is highly dependent on the weather, with below-average sunshine and/or wind, or above-average rainfall, depressing output (and vice versa).
3. Demand for peat is generally much more stable than production: the resulting surpluses or deficits are borne by buffer stocks of dried peat.
4. Tonnages are generally expressed in terms of air-dried peat (35%-55% moisture content).
5. Sources: *2004 Energy Statistics Yearbook*, United Nations Statistics Division; estimates by the Editors

COUNTRY NOTES

The Country Notes on Peat have been compiled by the Editors, drawing principally upon the following publications:

- Lappalainen, E. (editor); 1996; *Global Peat Resources*; International Peat Society, Finland;
- Couch, G.R.; 1993; *Fuel peat - world resources and utilisation*; IEA Coal Research, London.

Information from other sources (including WEC Member Committees) has been incorporated when available.

Argentina

There are some 500 km^2 of peat bogs on the Isla Grande de Tierra del Fuego at the southern tip of the republic. These deposits constitute some 95% of Argentina's peatlands: other peat bogs exist in the highland valleys of the Andean Cordillera and in other areas. However, economic exploitation of peat is almost entirely confined to Tierra del Fuego, where relatively small amounts (circa 3 000 m^3 per annum) are extracted, almost entirely for use as a soil-improvement agent. Consumption of peat for fuel is currently negligible.

Belarus

The peatlands of Belarus are by far the most extensive in Eastern Europe (excluding the Russian Federation), amounting to 24 000 km^2. The largest areas of peat formation are in the Pripyat Marshes in the south and in the central area around Minsk. Peat has been used as a fuel for many years, with the highest consumption during the 1970s and 1980s. The use of peat as a power station fuel ceased in 1986; fuel output in recent years has been largely confined to the production of peat briquettes, mainly for household use.

Out of a total fuel peat production of around 2 million tonnes per annum, deliveries to briquetting plants account for 85-90%. Consumption of peat by CHP and heat plants amounts to about 200 000 tpa, with the balance of peat supply being consumed by a variety of small-scale users. Current annual output of peat briquettes is approximately 1.2 million tonnes, of which half is consumed in the residential sector and approaching a quarter is exported.

The IPS National Committee for Belarus reports that 2005 peat production was 2.36 million tonnes.

Brazil

The area of peatland has not been precisely established but it is believed to be at least 15 000 km^2, which makes it the largest in any South American country. There are extensive deposits in the Middle Amazon and in a large marshy plain (Pantanal) near the Bolivian border. Smaller areas of peatland exist in some coastal locations; those in the industrialised south-east of Brazil (in the states of Espírito

Santo, Rio de Janeiro and São Paulo), and further north in Bahia state, have attracted interest as potential sites for the production of peat for energy purposes. The Irish peat authority Bord na Móna carried out preliminary surveys in Brazil in the early 1980s but no production of peat for fuel has yet been developed.

The total amount of peat *in situ* has been estimated as 25 billion tonnes. According to the Ministry of Mines and Energy, 'measured/indicated/inventoried resources' of peat amount to just over 129 million tonnes, with an 'inferred/estimated' additional amount of 358 million tonnes.

Burundi

There are appreciable areas of peatland, totalling about 140 km^2. The principal known deposits lie beneath the Akanyaru swamp complex in northern Burundi: these cover about 123 km^2 and are estimated to contain 1.42 billion cubic metres of peat *in situ*. The proved amount in place (expressed in terms of recoverable dry peat) was reported in 1992 to be 56 million tonnes.

Peat has been proposed as an alternative fuel to wood, in order to reduce deforestation, and a number of surveys have been conducted. Fuel peat is currently produced by semi-manual methods at four locations, but usage of the resource remains predominantly for agricultural purposes. The UN Statistics Division estimates annual production and consumption of fuel peat as 5 000 tonnes.

Canada

Canada's peatlands are estimated to exceed 1.1 million km^2 in area and are the largest in the world.

There have been a number of assessments of the potential for using peat as a fuel (including for power generation) but at present there is virtually no use of peat for energy purposes and none is likely in the immediate future. Canada is, however, a major producer (and exporter) of peat for horticultural applications.

China

Peatlands totalling some 10 000 km^2 are quite widely distributed but do not have a high overall significance in China's topography, accounting for only about 0.1% of the country's land area. The principal peat areas are located in the region of the Qingzang Plateau in the southwest, in the north-east mountains and in the lower Yangtze plain in the east.

Peat has been harvested for a variety of purposes, including fuel use, since the 1970s. Some is used in industry (e.g. brick-making), but the major part of consumption is as a household fuel. Peat has been reported to be sometimes mixed with animal dung as input to biogas plants. No information is available on the current level of peat consumption for fuel. The Chinese WEC Member Committee reported production and consumption of 600 000 tonnes in 1990 for an earlier *Survey*.

Denmark

Human activities, chiefly cultivation and drainage operations, have reduced Denmark's originally extensive areas of peatland from some 20-25% of its land area to not much more than 3%. Out of a total existing mire area of some 1 420 km^2, freshwater peatland accounts for about 1 000 km^2, the remainder consisting of salt marsh and coastal meadow. Commercial exploitation of peat resources is at a low level: in 1995 the area utilised was some 1 200 ha, producing about 100 000 tonnes per annum. Almost all the peat produced is used in horticulture; fuel use is negligible.

Estonia

Peatlands are a major feature of the topography of Estonia, occupying about 22% of its territory. They are distributed throughout the country, with the largest mires being located on the plains. Estonia has a long history of peat utilisation: mechanised harvesting dates from 1861, whilst the first peat-fired power plant was operating in 1918 and peat briquetting began in 1939. Total peat resources are estimated to be 1.64 billion tonnes, of which active resources amount to 1.12 billion tonnes. At 1 January 2004, economically and ecologically exploitable deposits of highly-decomposed (HD) peat, suitable for fuel use, were some 241 million tonnes.

The use of peat for fuel is currently in the order of 300 000 tonnes per annum. Much of the peat is consumed in the form of briquettes - in 2004 briquette production totalled 68 000 tonnes; 78 000 tonnes of briquettes were exported (some ex-stockpiles), the balance being very largely consumed in the residential sector. Most of the consumption of un-briquetted peat is accounted for by district heating and electricity generation (mainly CHP); 2005 usage in this sector was some 10 000 tonnes. Some sod peat (about 28 000 tonnes in 2004) is exported.

Finland

With their total area of some 89 000 km^2, the Finnish peatlands are some of the most important in Europe and indeed globally - Finland has the highest proportion of wetlands of any nation in the world. Peat deposits are found throughout Finland, with a greater density to the west and north of the country.

The area of peat potentially suitable for commercial extraction is 6 220 km^2, of which about 22% contains high-grade peat suitable for horticulture and soil improvement. The remaining 78% (together with other deposits from which the surface layers have been harvested for horticultural use) is suitable for fuel peat production. In 1995, the total area used for peat production was only 530 km^2, from which 25.8 million m^3 were extracted for fuel use and 2.1 million m^3 for non-energy uses.

In 2004, CHP plants accounted for almost 52%, and power stations for 31%, of the total national consumption of fuel peat; industrial users consumed 12%, the balance being used in heat plants (4%), and directly in the residential and agricultural sector (1%).

Germany

The majority of around 14 000 km^2 of peat-lands is in the northern Länder of Lower Saxony, Mecklenburg-West Pomerania and Brandenburg. Most of Germany's fens have been drained, the land being used for agriculture, mainly grassland farming.

Out of the total area covered by raised bogs, approximately 60% is farmed, with only a small proportion (less than 10%) exploited for peat production. Present-day use of peat for fuel in rural areas is reported to be very limited, virtually all production being destined for agricultural/horticultural uses or for the manufacture of activated carbon. About 120 thousand tonnes per year of energy-grade peat is exported.

Greece

Despite the drainage of large stretches of former fenland, and the loss of much peat through oxidation and self-ignition, peat resources in Greece are still quite considerable. The largest deposits are in the north of the country, at Philippi in eastern Macedonia and Nissi in western Macedonia. The Philippi peatland covers about 55 km^2 and is nearly 190 m deep - the thickest known peat deposit in the world.

Fuel Peat: World Resources and Utilisation quotes total reserves as 4 billion tonnes: the proportion of this amount that might be suitable for fuel use is indeterminate.

Peat resources in Greece have not so far been commercially exploited, either for use as fuel or for agricultural, horticultural or other purposes. Schemes for peat-fired electricity generation at Philippi and Nissi have been proposed in the past, but have subsequently been abandoned.

Iceland

Peatlands cover some 10 000 km^2 or about 10% of Iceland's surface area; the ash content of the peat is usually high (10-35%), owing to the frequent deposition of volcanic ash. Although peat has traditionally been used as a fuel in Iceland, present-day consumption is reported as zero. In the past, an important non-energy application of peat consisted of the use of 'peat bricks' in the construction of buildings.

Indonesia

The peatlands are by far the most extensive in the tropical zone (estimated as up to 270 000 km^2) and rank as the third largest in the world: they are located largely in the sub-coastal lowlands of Kalimantan and Sumatra. A feasibility study was carried out between 1985 and 1989 regarding the use of peat for electricity generation in central Kalimantan; no project resulted, but a small peat-fired power plant has operated in southern Sumatra.

Ireland

More than 17% of the republic's land surface is classified as peatland. Peat deposits totalling nearly 12 000 km^2 are widely distributed, being especially prominent along the western seaboard and across the Midland Plain in the centre of the island. Domestic consumption of peat for energy purposes in Ireland dates back to prehistoric times, with documentary evidence of its use existing from as early as the 8th century. After large stretches of the island's forests were cleared in the 17th century, peat (called 'turf' when cut) became the only fuel available to the majority of households.

Mechanical methods of extraction were adopted on a large scale following World War II, both for the production of milled peat (used as a power-plant fuel and in the manufacture of peat briquettes) and to replace manual cutting of sod peat for household use. Production of fuel peat in 2004 (as reported to the IEA) was about 4.4 million tonnes, with consumption of around 2.7 million tonnes.

Out of current annual consumption of peat for energy purposes, nearly 70% is used in power stations and heat plants, 16% is briquetted and 13% consists of sod peat, used predominantly as a residential fuel. Peat briquettes are also almost all used as household fuel.

Since its foundation in 1946, the Irish Peat Development Authority (Bord na Móna) has promoted the economic development of Ireland's peat resources. A number of power stations and briquetting plants have been built near peat deposits. A programme has been undertaken to replace five old peat-fired power plants with three more efficient and more environmentally-friendly peat-fired power plants. The first of the new stations, built by Edenderry Power Ltd near Clonbullogue, County Offaly, with a net output capacity of 120 MW, was commissioned in November 2000. It consumes approximately 1 million tonnes of milled peat per annum. The other new stations were constructed at Lough Ree (100 MW), replacing the existing Lanesboro station in December 2004, and West Offaly (150 MW), which replaced Shannonbridge in January 2005. The peat consumption rates of Lough Ree and West Offaly are 800 000 tpa and 1 245 000 tpa, respectively.

During the last five fiscal years, Bord na Móna's production of milled peat has ranged from 2.7 to 5.1 million tonnes, with an average annual level of just over 4 million tonnes. Output of peat briquettes averaged 252 000 tpa. Sales of milled peat to power stations rose from just under 2 million tonnes in 2004/05 to nearly 2.8 million tonnes in 2005/06, reflecting the first full year of operation of the three new peat-fired plants.

Italy

There are significant resources of peat (circa 1 200 km^2) in Italy, mostly in Piedmont, Lombardia and Venezia in the north of the country. *Fuel Peat: World Resources and Utilisation* gives the estimated reserves as 2.5 billion tonnes: the proportion of this amount that might be suitable for fuel use is indeterminate.

Although peat has been used for fuel during the past, notably in the context of wartime shortages of other sources of energy, no present-day usage has been reported.

Latvia

Peatlands cover about 6 400 km^2, or almost 10% of Latvia's territory, with the major deposits being located in the eastern plains and in the vicinity of Riga. Of the estimated total tonnage of peat resources (1 500 million tonnes), 230 million tonnes is suitable for fuel use.

Peat has been used in agriculture and as a fuel for several hundred years: output peaked in 1973, when fuel use amounted to 2 million tonnes. By 1990, the tonnage of peat extracted had fallen by 45% and fuel use was down to only about 300 000 tonnes. There has been a steep decline in consumption since then, with deliveries to the Riga CHP-1 plant coming to an end in 2004. The production of peat briquettes ceased in 2001. Currently, only minor tonnages of peat (less than 10 000 tpa) are consumed by heat plants and industrial users.

Lithuania

Peatlands (totalling nearly 5 000 km^2) are widespread, with the larger accumulations tending to be in the west and south-east of the country. About 71% of the overall tonnage of peat resources is suitable for use as fuel. Energy use of peat fell from 1.5 million tonnes in 1960 to only about 0.1 million tonnes in 1985, since when consumption has declined further to around 50 000 tonnes per year. The principal peat consumers are heat plants, producers of semi-briquettes, and households; the last-named also account for virtually all of Lithuania's modest consumption of locally-produced peat semi-briquettes, together with about 5 000 tpa of briquettes imported from Belarus.

Norway

Although there are extensive areas of essentially undisturbed peatland, amounting to nearly 24 000 km^2, peat extraction (almost all for horticultural purposes) has been at a relatively low level in recent years.

Peat had traditionally been used as a fuel in coastal parts of the country; unrestrained cutting led to considerable damage to the peatland, which in 1949 resulted in legislation to control extraction.

Poland

The area of peatland is some 12 000 km^2, with most deposits in the northern and eastern parts of the country.

Much use was made of peat as a fuel in the years immediately after World War II, with some production of peat briquettes and peat coke; by the mid-1960s fuel use had, however, considerably diminished. Current consumption of peat is virtually all for agricultural or horticultural purposes.

Romania

There are just over 70 km^2 of peatlands. Peat production for energy purposes has been only a few thousand tonnes per annum in recent years, with consumption confined to the residential and agricultural sectors.

Russian Federation

According to *Global Peat Resources*, the total area of peatlands is some 568 000 km^2: the deposits are widely but unevenly distributed throughout the Federation. The principal peat areas are located in the north-western parts of European Russia, in West Siberia, near the western coast of Kamchatka and in several other far-eastern regions. The Siberian peatlands account for nearly 75% of the Federation total.

Total peat resources are quoted in *Global Peat Resources* as 186 billion tonnes, second only to Canada's in world terms. Of the total, 11.5 billion tonnes have been the subject of detailed surveys and a further 6.1 billion tonnes have been preliminarily surveyed.

The bulk of current peat production is used for agricultural/horticultural purposes. Peat deposits have been exploited in Russia as a source of industrial fuel for well over a hundred years. During the 1920s, the use of peat for power generation expanded rapidly, such that by 1928 over 40% of Soviet electric power was derived from peat. Peat's share of power generation has been in long-term decline, and since 1980 has amounted to less than 1%.

Approximately 5% of the exploitable peat deposits are used for fuel production, which currently amounts to around 1.5 million tonnes per annum. The main users are CHP plants and briquetting works; most of the residual consumption of peat, whether as such or in the form of briquettes, takes place in the rural residential sector.

Sweden

In Western Europe, the extent of Sweden's peatlands (64 000 km^2 with a peat layer thicker than 30 cm) is second only to Finland's: the deposits are distributed throughout the country, being particularly extensive in the far north.

Energy peat production has been gradually increasing in recent years and is now in the region of 1.3 million tonnes per annum.

The use of peat as a household fuel has never been of much significance. Production of peat for industrial energy use began during the 19th century and, after reaching a peak level during World War II, declined to virtually zero by 1970. Use of peat as a fuel for power stations and district heating plants started in the mid-1980s and now constitutes by far the greater part of consumption. In 2004, CHP plants accounted for 71% of total consumption, heat plants for 26% and industrial users for the remaining 3%.

Ukraine

There are over 10 000 km^2 of peatlands, more than half of which are located in Polesie, in the north of the country, where they account for 6.4% of the surface area. The other main area for peat deposits is the valley of the Dnieper, in particular on the east side of the river. Peat production rose during the period of the communist regime, reaching 7.5 million tonnes in 1970, when 73% was used in agriculture and

27% for fuel. In recent years consumption of peat for fuel purposes has fallen to less than 0.7 million tonnes per annum, all consumed by households.

United Kingdom

The peatlands of Great Britain cover an area of some 17 500 km^2, most deposits being in the northern and western regions; Scotland accounts for about 68% of the total area of peat, England for 23% and Wales 9%.

There are about 1 700 km^2 of peatland in Northern Ireland, mostly located in the western half of the province.

The total UK peatland area is nearly twice that of Ireland, but the extraction of peat is on a very much smaller scale: in Great Britain, commercialised peat extraction takes place on only some 5 400 ha (equivalent to about 0.3% of total peatland). Almost all peat industry output is for the horticultural market; there is, however, still quite extensive (but unquantified) extraction of peat for use as a domestic fuel in the rural parts of Scotland and Northern Ireland. Anecdotal evidence suggests that peat-cutting for fuel in Scotland has declined in recent years, having been replaced to some extent by purchases of peat briquettes imported from Ireland.

About 20 000 tonnes of air-dried sod peat has been reported by the International Peat Society as being produced for energy purposes in 2002, some of which was exported to Sweden.

United States of America

In 1995 the total area covered by peat soils (known as histosols) was some 214 000 km^2, of which Alaska accounted for just over 50%. In the contiguous United States, the major areas of peat deposits are in the northern states of Minnesota, Michigan and Wisconsin, along the eastern seaboard from Maine to Florida and along the Gulf coastal region as far as Louisiana.

The potential uses of peat as fuel were evaluated during the 1970s; a Department of Energy study published in 1980 covered - in addition to direct combustion uses - the potential for producing liquid fuels from peat.

Interest in developing the use of peat for energy purposes has diminished since 1980. A small (23 MW) power plant was constructed in 1990 in Maine, to be fuelled by local peat. Initial problems associated with the use of inappropriate harvesting equipment were overcome but it was then difficult to obtain further permits to exploit the larger bog area required; the boilers were subsequently fuelled mainly by wood chips.

9. Bioenergy

COMMENTARY

Introduction

The term bioenergy denotes the use of vegetable matter as a source of energy; it covers a variety of fuels, with applications in all the major sectors of consumption – power generation, transportation, industry, households, etc. The present Commentary discusses the current status and future prospects of some of the major players, with an emphasis on those with increasing significance in the global picture.

Wood fuels

From the 2004 *Survey of Energy Resources* it is evident that wood fuels make up about 50% (24 EJ) of the IEA estimate of 48 EJ classified as combustible renewables and waste (IEA, 2006). As was noted in the Wood chapter of the 2004 *Survey*, there are two very different populations using wood fuels. One, typically an OECD member country, uses highly-efficient combustion technology under tight regulations on emissions. The other (representing by far the majority - estimated at three billion people) uses small-scale appliances (three-stone fires or cooking stoves) that are both inefficient and highly polluting. The two populations are also different with respect to the estimation of their energy consumption; the former increasingly uses wood fuels that are traded commercially, while the latter still operates in an informal sector for which only estimates can be made.

Figure 9-1 Wood fuels: 2005 consumption (PJ)*
Source: FAOSTAT – Forestry

	Fuelwood	Charcoal	Black Liquor	Total
Africa	5 633	688	33	**6 354**
North America	852	40	1 284	**2 176**
LAC	2 378	485	288	**3 150**
Asia	7 795	135	463	**8 393**
Europe	1 173	14	644	**1 831**
Oceania	90	1	22	**113**
Total	17 921	1 361	2 734	**22 017**

*Note: all FAOSTAT-Forestry data revised to the version of March 2007 for the reporting year of 2005. Fuelwood data were available expressed volumetrically i.e. cubic metres, converted (after density conversion) at 10 GJ/tonne. Charcoal data were available, expressed in terms of mass, converted at 30 GJ/tonne. Black liquor is not reported; however, bleached and bleached sulphate pulp are reported in terms of mass. Based on average mass yields of pulp for the two processes (bleached = 0.45, unbleached = 0.55) the pulping liquor energy was calculated on the basis that the majority of its energy content is lignin with a heating value of 24 GJ/tonne. North America is defined as the NAFTA region and includes Canada, Mexico and the United States. LAC represents the Latin American countries together with the Caribbean.

Statistics on wood fuel use are poor in both developed and developing countries because of insufficient institutional awareness, resulting in different approaches to making estimates. There are many different aspects of government jurisdiction involved in the wood fuel sector. Moreover, the lack of reliable statistics exacerbates the problems of supply management and the mitigation of negative impacts from the use of wood fuels. For example, forestry departments are concerned with the total wood flow out of forests; energy department concerns are with estimates of household, commercial and industrial energy requirements, while environmental regulators may be concerned with resource depletion (soil, water and biodiversity) and emissions impacts, and by no means last, the health sector may be following the effects of household emissions on chronic diseases.

One of the most critical of these issues is that of indoor air pollution, which featured in a special session addressing household energy and health at the 14th meeting of the Commission for Sustainable Development (CSD-14). The World Health Organization (WHO) simultaneously released *Fuel for Life: household energy and health* (Rehfuess, 2006) in which the call for both improved stoves and the substitution of modern fuels such as LPG is made.

In the 2004 update of the UN Food and Agricultural Organization's (FAO) interactive Wood Energy Statistics (i-WESTAT) (Drigo and Trossero, 2005), there is a detailed analysis of the state of different statistical sources of wood fuels. With the advent of new technologies based on geographic information systems (GIS) and their integration with survey activities, the FAO has developed the Wood Fuel Integrated Supply/Demand Overview Mapping (WISDOM) methodology. WISDOM has demonstrated that accurate, and indeed exhaustive, wood energy statistics can be obtained at several levels, ranging from regions to local forests (Masera, Ghilardi, et al., 2006). The early applications of WISDOM are not yet sufficient to revise the information base, so the present analysis of wood fuel will continue to rely on the FAOSTAT database (FAO, 2006).

The current wood energy situation. Wood Fuel is classed into three main commodities: fuelwood, charcoal and black liquor. Black liquor is the spent pulping chemicals and the lignin component of wood after chemical pulping. It is fired in a chemical recovery boiler and process steam and electricity are also produced. Fuelwood and charcoal are the traditional wood forest products, and even today almost half of all of the forest harvest is for energy, with the remainder for industrial use (lumber, veneer and

Figure 9-2 Electricity production from biomass (TWh)
Source: Observ'ER, 2006

	1995	2002	2003	2004	2005
Solid biomass	85.3	110.0	118.2	131.4	134.9
Biogas	6.0	16.9	18.3	20.7	24.8
Liquid biomass			0.8	0.6	0.9
Municipal solid waste (MSW)*	13.4	21.3	25.0	24.0	22.8
Total	104.8	148.2	162.2	176.6	183.4

* MSW data are solely for the renewable content of the municipal waste stream

paper). Some of this is indirect, in that timber that is harvested may first be converted into board and the residues, such as bark, trim ends, and sawdust, then transferred from the wood industry into the energy sector, as is the case with black liquor. As well as this secondary generation of wood energy, there is a tertiary source in the form of post-consumer residues that arise from the manufacture, use or disposal of wood products. This source often ends up in the municipal waste stream and in many OECD countries it is separated from the stream, either for recycling or for use in energy products.

Charcoal is produced by the thermal conversion of wood (and other biomass). This transformation has losses in the form of combustible gas and condensable materials (wood tar), which are not always recovered for either material applications or energy purposes. The energy efficiency of charcoal production ranges from 25% in Africa (using mainly artisanal methods) to 48% in Brazil which uses industrial kilns with extensive energy and materials recovery. The FAOSTAT forestry database uses a single conversion of 6 m^3 roundwood solid volume equivalents for one tonne of charcoal, corresponding to nearly 50% efficiency.

The values for 2005 are comparable to those of the 2004 SER. Differences are most likely due to the general improvement in estimates at the country level, as the FAO forestry group improves the overall methodology. Given the relative imprecision of the estimates it is not possible to see trends that will have a major impact on the values of previous years.

Biomass for Electricity Generation

The largest secondary transformation of biomass after charcoal production is in the electricity sector. For many years biomass processing industries such as sugar, wood products and chemical pulping (black liquor) have installed combined heat and power (CHP, also known in the USA as cogeneration) plants. Many of these have been relatively low-steam-temperature installations, with only sufficient electricity to meet the plant processing needs. Since the 1970s there has been a large expansion of biomass-based electricity generation, with an increased emphasis on generating efficiency, resulting in electricity exports into liberalised or deregulated markets. In addition, there has been an expansion of district heating schemes with CHP in Scandinavia, based on straw in Denmark and wood residues in Sweden and Finland. In countries with extensive coal-fired electricity generation there have been incentives under climate schemes to co-fire biomass in order to achieve carbon offsets of up to 15%. Germany and other countries have also stimulated the generation of electricity from urban residue streams in energy from waste (EFW) facilities, from land fill methane, and from anaerobic digestors associated with the animal husbandry sector. India, China and Brazil have also invested in rural electricity generation from producer gas and vegetable oils.

Figure 9-3 Leading biopower producing countries, 2005
Source: Observ'ER, 2006

	Production (TWh)	Percentage of world
USA	56.3	30.7
Germany	13.4	7.3
Brazil	13.4	7.3
Japan	9.4	5.1
Finland	8.9	4.9
UK	8.5	4.7
Canada	8.5	4.6
Spain	7.8	4.3
Rest of World	57.1	31.1

In 2005 estimated total electricity generation was about 180 TWh from an installed capacity in excess of 40 GW. At an average 20% efficiency this corresponds to 3 EJ of primary energy input. The overall rate of growth has been greater than 5% in the last decade as shown in Fig. 9-2. The recent negative trend for MSW is a consequence of increased material recycling, together with reductions in the amount of biomass-derived materials entering the waste stream.

The eight leading countries with biomass-based electricity production are all members of the OECD, except for Brazil. Brazil is also unique in that at present almost all of its input is solid biomass, much of it bagasse from the expanding sugar cane-based alcohol fuel industry. The OECD countries generally have contributions of up to 10% of the total from both MSW (EFW) and biogas, with a large contribution from landfill sites containing biodegradable urban residues. The rising contribution of liquid fuels reflects the increasing use of vegetable oils in combustion turbines and diesel generation.

Biopower trends. A key issue for the biopower sector is efficiency. The move towards co-firing with coal has the advantage that the efficiency when firing the blended fuel is that of the original coal boiler with little or no loss relative to the coal component. CHP installations are efficient in generally satisfying the primary thermal requirement, with the electricity output following the thermal load. Typically, CHP electrical efficiency is higher, with improved steam conditions of temperature and pressure, a trend which could result in the bagasse sector becoming much more efficient.

A typical sugar mill has an electricity demand of about 20-30 kWh/t_c. One tonne of cane (t_c) typically provides 150 kg of sugar and 90 kg of bagasse (dry basis). The thermal requirements for refining sugar are easily met from the generated bagasse, such that CHP is the preferred option. Low-efficiency mills generate 21 bar steam and produce about 60-70 kWh/t_c for export, while more recent investments have been in 88 bar steam with the capability of exporting 130 kWh/t_c.

The World Alliance for Decentralized Energy (WADE) has estimated that the 11 leading countries had 3.9 GW of installed bagasse-based generating capacity with Brazil contributing 1.7 GW (Bell, 2005) due to PROFINA, a programme guaranteeing power sales to the grid. Mauritius (Deepchand, 2001), with 40% of all electricity generated from bagasse, has demonstrated (through a programme taking over 20 years) the restructuring needed in the sugar industry to access sufficient bagasse and capital for this renewable resource to make a major, high-efficiency contribution. The capacity consists of seasonal generation in bagasse-only plants and also two larger more efficient plants that are

Figure 9-4 World production of ethanol (hm^3)
Sources: national statistics, Renewable Fuels Association, F.O. Licht publications

Country	2004	2005	2006
Brazil	15.1	16.0	17.0
USA	13.4	16.2	18.4
China	3.65	3.80	3.85
India	1.75	1.70	1.90
France	0.83	0.91	0.95
Russia	0.75	0.75	0.75
Germany	0.27	0.43	0.77
South Africa	0.42	0.39	0.39
Spain	0.30	0.35	0.46
UK	0.40	0.35	0.28
Thailand	0.28	0.30	0.35
Ukraine	0.25	0.25	0.27
Canada	0.23	0.23	0.58
Total of above	**37.6**	**41.6**	**45.9**

Notes:

1. F.O. Licht data for 2005 quotes a world total of approximately 46 hm^3, including many minor producing countries;
2. 2006 data are estimated and rely on announced plant construction and the anticipated start-up date. Although even larger capacities are projected for later years, many of these plants may not be built;
3. China is understood to have placed a moratorium on plant construction in 2006.

fired with coal in the off-season. The overall potential of sugarcane bagasse in power generation is clearly dependent on both technical and socio-commercial factors. However, using high-pressure steam technologies with the resources indicated in Table 9-1, the technical potential is more than 130 TWh annually.

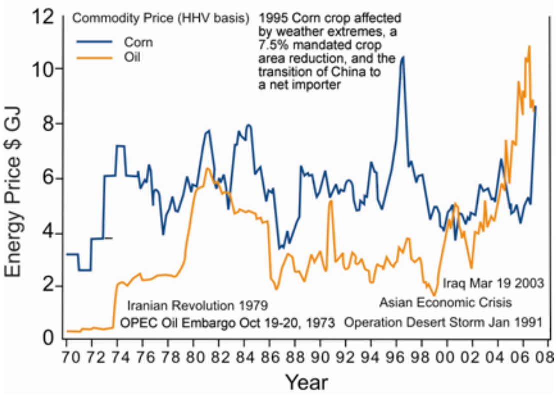
Biofuels

Ethanol

2006 was the year in which biofuels for transportation came into very public prominence, as rising world crude oil prices stimulated the US President in his January state-of-the-union address to advocate increased support for ethanol, both in its current production from maize and the future option of producing it from the extensive lignocellulosic resources contained in agricultural straws and wood. The US Congress supported what at the time seemed to be a very ambitious and large Renewable Portfolio Standard (RPS) of 28.4 hm^3 by 2012. In fact, the rate of increase in ethanol production had just reached 25% per year and the amount produced in 2005 in the USA stood at 16.2 hm^3 as shown in Fig. 9-4, suggesting that the RPS goal could be reached within 3 years, by 2008.

The continued increases in the price of crude oil in 2005 and 2006 resulted in a reversal of the traditional relationship between the price of biomass energy and that of crude oil, something not seen since the 1930s. Fig. 9-5 shows the trend in nominal price terms of the higher heating values of Illinois yellow corn (maize) and of the average cost of imported crude into the USA each month since before the first energy crisis. As a consequence of the high prices of traded crude oil, many countries advanced their biofuel goals and, in the case of Brazil and the USA, large production gains occurred. The proportion of the world's gasoline pool provided by the 2006 estimate of ethanol output is about 2.5% (1.1 EJ of ethanol and 37.5 EJ of gasoline). The potential of biofuels for transportation is however quite finite; current global food production corresponds to a primary energy content of about 30 EJ/yr, while crude oil

Figure 9-5 Corn and imported crude oil: nominal prices
Sources: USDA and EIA



alone is around 160 EJ/yr. Thus the projected large growth of ethanol from maize in the USA could use the equivalent of 40% of today's crop (up from around 16%). The USA is the swing producer of maize, contributing about 40% to internationally-traded corn and it is hardly surprising that a drought in Australia that impacts on the production of wheat at a time of increased demand for fuel grain would drive the corn price up very rapidly, as is seen at the end of 2006 and in the early part of 2007 in Fig. 9-5.

The expansion of biofuels is not without controversy, as the production of ethanol from corn is only marginally energy-positive at about 1.4:1, while that from sugarcane in Brazil has a ratio of about 8 units of renewable liquid fuel to one of fossil energy input. And whereas Brazil has foregone most agricultural subsidy to its sugar industry, the agricultural sectors of both the USA and the EU countries are engaged in vast subsidies on agricultural commodities in general, and on ethanol or other biofuels specifically. The US subsidy regime for ethanol costs about US$ 5 billion per year at present. Agricultural subsidies have been challenged during the Doha round of World Trade Organization negotiations as being bad for the environment (by encouraging intensive agriculture) and for their negative effects on the development of agriculture in third-world countries. Many of these countries would be capable of becoming major players (using Brazilian biofuels as an example) if there were neither subsidies nor tariff barriers such as the US$ 143/m^3 (54 c/US gal) imposed by the USA on Brazil.

Biodiesel

The other significant biofuel is biodiesel, which is currently produced from vegetable oils, animal fats and grease by esterification. The vegetable oils with carbon chain lengths of between 16 and 22 carbon atoms are generally in the form of triacyl glycerides (TAG) which on transesterification with methanol produce glycerol as a by-product and FAME (fatty acid methyl ester) as the precursor to biodiesel. After FAME purification and testing for compliance with either EN 14214 or ASTM D6751 standards the product can be sold as biodiesel and used as blends - typically B5 (5% biodiesel) to B20, depending on the engine warranties.

The second-generation biodiesel is often called 'renewable diesel' and is produced by treating vegetable oil with hydrogen over catalysts in oil refineries, to either blend or be co-processed with 'fossil diesel'. The resultant product can be used in the range of B5 – B50. As a fuel, the FAME biodiesel has about 90–95% of the volumetric energy content of regular diesel, and in combustion reduces some of the particulate and carbon monoxide emissions. The effect on NO_x is not so clear cut, with many studies showing a slight increase.

In addition to vegetable oils, animal fats such as tallow and waste grease can also be converted to FAME; they are the lowest-cost resources available, mainly in urban areas.

The commercial resource base for vegetable oils comprises about 20 different species with

Figure 9-6 Biodiesel: production (thousand tonnes)
Sources: European Biodiesel Board; Malaysian Palm Oil Board; National Biodiesel Board, USA

	2004	2005	2006
Germany	1 035	1 669	2 681
France	348	492	775
Italy	320	396	857
Malaysia		260	600
USA	83	250	826
Czech Republic	60	133	203
Poland		100	150
Austria	57	85	134
Slovakia	15	78	89
Spain	13	73	224
Denmark	70	71	81
UK	9	51	445
Other EU	6	36	430
Total	**2 016**	**3 694**	**7 495**

soybean oil, palm/palm kernel oil, sunflower, rapeseed (Colza), and coconut oils being the largest sources. According to the FAO Food Outlook series reports the 2004/2005 production of oils and fats was about 142 mt, with consumption running at around 138 mt and a 22% annual reserve stock ratio to consumption (www.fao.org/waicent/portal/statistics_en.asp).

World consumption for all purposes is increasing at about 4% per year, however the largest growth rates are in palm oil which together with soy oil comprise 50% of the annual vegetable oil production. Biodiesel production is increasing rapidly, but the statistics are not yet reliable enough to determine total production. However, FAME/biodiesel production capacity is better estimated and is the primary basis of production statistics.

Despite the current minority position of biodiesel relative to ethanol, the adoption of mandates in several countries will fuel a large growth in the near future. Brazil, for example, has a nationwide mandate for B2 in 2008 resulting in an estimated 1.1 hm^3 demand for biodiesel (935 kt). The EU mandates for 5.75% biofuels in the transportation sector by 2010 are driving the rapid growth of biodiesel in the major EU economies and, like ethanol, production has leapt in the last few years (Fig. 9-6).

The estimated output for 2006 at 7.5 mt is equivalent to 6.8 mtoe or 0.3 EJ energy equivalent. While the energy balance for rapeseed biodiesel is around 4 units of energy for each unit of fossil input, it can be as high as 8:1 for high-yielding palm oil biodiesel. The processing of both rapeseed and soy produces considerable quantities of co-product meal which is used as an animal feed. The growing fuel market is introducing distortions into the animal-feed supply system, which is also having to accommodate increasing amounts of dried distillers' grains and solubles (DDGS) from the corn-ethanol production system. The two largest producers of palm oil are Malaysia and Indonesia and in 2006, owing to the number of proposed biodiesel facilities, the two countries agreed on a limit of 6 mt of palm oil capacity while the impacts of the anticipated expansion could be evaluated.

The agricultural commodity base of the current biofuels has ramifications for the sustainability of the food and animal-feed supply system, and many countries are looking to other biomass resources and second-generation biofuels for sustained growth.

The second-generation biofuels include renewable and green diesels. The former is a technology that incorporates vegetable oils into the crude oil-derived diesel production process to produce a renewable carbon-based diesel with no oxygen content and a very high cetane number, while the latter is the production of middle distillate by means of Fischer-Tropsch catalysts, using synthesis gas produced by the gasification of biomass. Fischer-Tropsch-like catalysts (Synthol process) can also produce ethanol and mixed alcohols. Alternative biotechnology approaches produce butanol in place of ethanol by the fermentation of sugars.

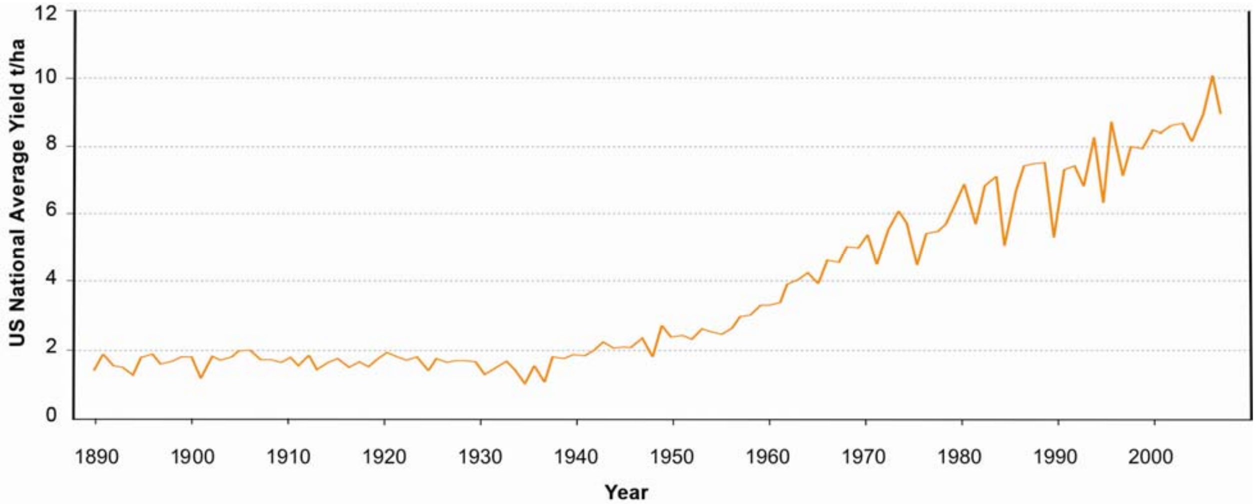
Biomass Resources

The existing large-scale use of forest resources for bioenergy detailed above implies that future expansion of biomass supplies will be from two very distinct streams: the residues associated with current agricultural commodity production and processing, and the planting of energy crops on available land. The latter is of course an option that is unavailable as a large-scale contribution in small highly-populated countries such as the UK and the Netherlands. But for countries such as Argentina, Brazil, Canada, the USA and Russia, as well as some in the eastern part of Europe, increased land utilisation is feasible.

Terrestrial biomass production can be determined from the characteristics of the different ecoregions and their associated biomes. Each ecoregion is defined by its climate, elevation and soils. Climate parameters include temperature, precipitation and solar insolation according to the pattern of the seasons and weather extremes. Satellite observations at several wavelengths of light can be used to prepare an estimate of the density of the green vegetation over the surface of the earth, by means of the normalized difference vegetation index (NDVI). The global estimates of net primary productivity (NPP - which is equivalent to the annual amount of photosynthetic carbon fixed in terrestrial biomass) were historically carried out by local sampling measurements in representative biomes that had been more or less mapped. Such extrapolation is now a thing of the past, as satellite sensor technology, mathematical models and geographic information systems (GIS) can now provide almost daily values of the NPP (Running, Nemani, et al., 2004) derived from the NDVI. The algorithm that provides the satellite-based value of NPP assumes a direct relationship between absorbed solar energy and the indices of vegetation, followed by biophysical restrictions such as temperature and water availability. The 2001 terrestrial value is estimated at 55.5 Pg carbon, or 489 g carbon/m^2 on vegetated land (Running, Nemani, et al., 2004) equivalent to 1.665 ZJ of primary energy.

These methods can be extended to predict biomass productivity with different crops that have their responses to the biophysical parameters incorporated into calibrated crop growth models. Typically the biome characteristics are described as Agroecological Zones (AEZ) which following an environmental approach, provides a standardised framework for the characterisation of climate, soil and terrain conditions relevant to crop and forest

Figure 9-7 US Corn yield
Source: USDA



species production, and uses environmental matching procedures to identify limitations of prevailing climate, soil and terrain for assumed management objectives. Such techniques have been used, for example to evaluate the potential for energy crops like miscanthus and willow in eastern Europe and Asia (Fischer, Prieler, et al., 2005), and incorporating land-use restrictions in the GIS treatment. Because these techniques often assume crops better suited to the biome than those currently occupying the land, and the use of best practices in crop management, the yields are usually greater than those generated by the current land use.

However, there are large-scale examples of how well the agricultural system can perform when all of the tools of modern biology are brought to bear. One of these is shown in the over 100-year record of corn yields in the contiguous 48 states of the USA in Fig. 9-7. The data are drawn from the US Department of Agriculture (USDA) and it can be seen that up until World War II the yield was quite low and the agriculture can only be described as extensive, using mainly animal power and low inputs of fertiliser. The last 50 years of the 20^{th} century saw, in turn: the transformation to a mechanised agriculture; the extensive use of fertiliser; the development of F1 hybrids; genetically engineered resistance to pests and weed-control and now the application of genomics and metabonics to optimise the breeding and development of corn cultivars for different regions. The next steps will include the development of corn crops that are specific in their yield of fermentable sugars in the production of ethanol.

The application of genetic engineering to increase drought tolerance, to improve nutrient-use efficiencies also promises to increase the availability of suitable land for growing improved crops.

Energy crops in the form of tree crops and herbaceous energy crops such as switchgrass in the USA and miscanthus in Europe have been the subject of considerable research and development, which is leading towards deployment. In a study conducted by the National Laboratories in the USA, the USDA and the Forest Service (Perlack, Wright, et al., 2005) established that the physical near-term sustainable biomass potential was over 1 Gt of biomass (18 EJ of primary energy equivalent) that could theoretically replace the crude oil currently imported into the US. A GIS-based atlas of the biomass resources of the United States is available from NREL (Milbrandt, 2005).

Forestlands account for an estimated 33% of the US land area. The US Department of Energy (DOE) and the USDA estimate that 333 mt of biomass feedstock are available annually from forestlands. This includes: 47 mt from harvesting for fuelwood, 131 mt from wood processing and pulp and paper mills, 43 mt from urban wood residues, 58 mt from logging and site-clearing operations, and 55 mt from forest fire-hazard reduction efforts. In evaluating the feedstock to be generated from logging and site-clearing and fire-hazard thinning, it was assumed that all forestland not currently accessible by roadways were excluded; all environmentally sensitive areas were excluded; equipment recovery limitations were considered; and recoverable forest materials categorised as either conventional forest products or biomass for bioenergy and biobased products. Agricultural lands are estimated to account for approximately 46% of the entire US land base with 26% consisting of grassland pasture and range, and 20% consisting of cropland. The DOE and USDA estimate that biomass feedstock available from agricultural lands, while still meeting food, feed and export demands, could supply 910 mt of biomass feedstock annually. This includes the following: 390 mt from crop residues, 343 mt from perennial energy crops (both tree and herbaceous), 80 mt of grains for biofuels, and 96 mt from animal manure, process residue, and miscellaneous feedstocks on a dry basis.

Nearly all of the material identified as a near-term resource in the USDOE study is comprised of lignocellulosic material, thus explaining the high degree of research investment into the conversion of these materials into biofuels. A key challenge is in realising the sugar content for bioconversions to first-generation biofuels such as ethanol and eventually to second-generation fuels. Alternative pathways could include thermal conversion and the Fischer-Tropsch process into middle distillates.

For the near-term development, much depends on utilising the process residues generated today. In the section above on electricity much of the opportunity was identified with so-called black liquor in the pulping industry. This is a very large-scale resource, as is the bagasse generated in the production of cane sugar or ethanol, which in total is about 160 mt of dry material worldwide, but has the same advantage in that it is available at the mill site for no additional cost of harvesting and collection.

Summary

From the assessments above the overall 2005–2006 biomass and bioenergy contribution would appear to be as follows:

- Thermal applications of wood energy: 18 EJ of primary energy;
- Black liquor: 2.7 EJ of primary energy;
- Charcoal: 1.4 EJ of secondary or product energy;
- Ethanol: 1.1 EJ of secondary or product energy;
- Electricity: 0.65 EJ of secondary or product energy;
- Biodiesel: 0.3 EJ of secondary or product energy.

The statistical base for these findings still has some risk of double-counting as the thermal input into ethanol processing, at least in Brazil, includes some heat only and some CHP applications of bagasse, and likewise the electricity figure will include some thermal input from bagasse and from black liquor as well as from biogas which is very difficult to estimate. Increasingly these estimates will be refined, especially in the case of the secondary or energy products output, all of which are properly commercialised and accounted for. And in a carbon-constrained world there will be an increasing effort to assess the role of the renewable carbon from the biosphere in all applications. Nevertheless, the overall near-term potential worldwide is far in excess of current consumption, as the assessment for the USA alone illustrates that there are almost 20 EJ of primary energy equivalent that would be accessible with today's technology. Similar findings are likely in the other four countries with large land areas and low population densities.

Ralph P. Overend
Editor, Biomass and Bioenergy
Canada

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TABLES

Table 9-1 Bagasse: estimated potential availability 2005 (thousand tonnes)

	Bagasse potential availability at 50% humidity	dry matter
Benin	16	8
Burkina Faso	130	65
Burundi	75	37
Cameroon	388	194
Chad	114	57
Congo (Brazzaville)	206	103
Congo (Democratic Rep.)	196	98
Côte d'Ivoire	473	236
Egypt (Arab Rep.)	3 912	1 956
Ethiopia	1 125	562
Gabon	68	34
Guinea	82	41
Kenya	1 733	866
Madagascar	89	44
Malawi	864	432
Mali	114	57
Mauritius	1 708	854
Morocco	191	95
Mozambique	865	433
Niger	33	16
Senegal	293	147
Sierra Leone	20	10
Somalia	49	24
South Africa	8 174	4 087
Sudan	2 373	1 186
Swaziland	2 128	1 064
Tanzania	908	454
Uganda	636	318
Zambia	808	404
Zimbabwe	1 401	700
Total Africa	**29 169**	**14 584**
Barbados	130	65
Belize	331	166
Costa Rica	1 299	649
Cuba	4 238	2 119
Dominican Republic	1 549	774
El Salvador	2 062	1 031
Guatemala	6 570	3 285

Table 9-1 Bagasse: estimated potential availability 2005 (thousand tonnes)

	Bagasse potential availability at 50% humidity	dry matter
Honduras	1 174	587
Jamaica	411	205
Mexico	18 319	9 159
Nicaragua	1 532	766
Panama	513	256
St. Christopher-Nevis	65	33
Trinidad & Tobago	108	54
United States of America	9 029	4 514
Total North America	**47 330**	**23 665**
Argentina	7 058	3 529
Bolivia	1 304	652
Brazil	91 720	45 860
Colombia	8 747	4 374
Ecuador	1 532	766
Guyana	802	401
Paraguay	381	191
Peru	2 264	1 132
Suriname	16	8
Uruguay	20	10
Venezuela	2 249	1 125
Total South America	**116 095**	**58 047**
Azerbaijan	6	3
Bangladesh	391	196
China	29 839	14 920
India	49 604	24 802
Indonesia	7 938	3 969
Japan	423	212
Malaysia	261	130
Myanmar (Burma)	489	245
Nepal	424	212
Pakistan	9 215	4 607
Philippines	7 119	3 559
Sri Lanka	196	98
Taiwan, China	147	73
Thailand	14 960	7 480
Vietnam	2 851	1 426
Total Asia	**123 861**	**61 931**
Unspecified	968	484

Table 9-1 Bagasse: estimated potential availability 2005 (thousand tonnes)

	Bagasse potential availability at 50% humidity	dry matter
Total Europe	**968**	**484**
Iran (Islamic Rep.)	1 206	603
Total Middle East	**1 206**	**603**
Australia	17 581	8 791
Fiji	997	499
Papua New Guinea	143	72
Western Samoa	7	3
Total Oceania	**18 729**	**9 364**
TOTAL WORLD	**337 357**	**168 679**

Notes:

1. Bagasse potential availability based on production of cane sugar published in the I.S.O. *Sugar Yearbook 2005*, International Sugar Organization;
2. Bagasse potential availability conversion factor from United Nations *Energy Statistics Yearbook 2004* (assumes a yield of 3.26 tonnes of fuel bagasse at 50% humidity per tonne of cane sugar produced)

COUNTRY NOTES

The Country Notes on Bioenergy reflect the data and comments provided by WEC Member Committees in 2006/7, supplemented where necessary by information provided for the 2004, 2001 and 1998 editions of the WEC *Survey of Energy Resources*.

Unless otherwise specified, the data relate to the year 2005.

Albania

Municipal solid waste		
quantity of raw material available	405	ttoe
Forestry/wood processing		
quantity of raw material available	237	ttoe

Data refer to 2002

Algeria

Municipal solid waste		
quantity of raw material available	5	million tonnes
Forestry/wood processing		
quantity of raw material available	3.7	million tonnes
Urban agricultural wastes		
quantity of raw material available	1.33	million tonnes

Argentina

Municipal solid waste		
quantity of raw material available *	48	million tonnes
Sugar cane bagasse		
quantity of raw material available	4.52	million tonnes
direct use from combustion	864	TJ
Forestry/wood processing		
quantity of raw material available	0.54	million tonnes
direct use from combustion	53.89	TJ
Wood		
quantity of raw material available	27.01	million tonnes
direct use from combustion	1 998	TJ
Agricultural residues **		
quantity of raw material available	34.34	million tonnes
direct use from combustion	6.4	TJ
Industrial agricultural residues		
quantity of raw material available	1.32	million tonnes
direct use from combustion	247.78	TJ
Cattle waste		

quantity of raw material available	14.2	million tonnes

* Corresponding to the residues dumped in the Relleno Sanitario de Villa Domínico landfill site. A demonstration project operated between 1978 and January 2004. A total of 48 037 673 tonnes of solid urban residues were accumulated in 25 years from the Ciudad Autónoma de Buenos Aires and the districts of Berazategui, Avellaneda, Quilmes, Almirante Brown, Florencio Varela, Lanús and Lomas de Zamora. The landfill generates some 195 million m^3 of biogas (50% methane) which partly generates electricity for on site use; the remainder is flared.

** Including all residues from soybean, maize, wheat, sorghum, rice and cotton.

Australia

Municipal solid waste		
quantity of raw material available	~ 6.9	million tonnes
yield of solid fuel	~ 9	GJ/tonne
electricity generating capacity	103 700	kW
Sugar cane bagasse *		
quantity of raw material available	11.4	million tonnes
yield of solid fuel	~ 9.3	GJ/tonne
electricity generating capacity	368 600	kW
Forestry/wood processing **		
quantity of raw material available	~ 25	million tonnes
yield of solid fuel (operational)	11	GJ/tonne
electricity generating capacity	76 500	kW
direct use from combustion	~ 66 000	TJ

Unless otherwise stated, data refer to 2002.

* 98 700 kW from landfill gas and 5 000 kW from MSW gasification (SWERF plant, Wollongong).

** Data refer to 1997. Sugar industry generation includes the Rocky Point sugar mill cogeneration plant, which uses some wood waste in the non-crushing season.

*** Includes Tumut pulp and paper mill power plants, plus Maryvale pulp and paper and Visy's plant in Brisbane. Direct combustion assumes 6 million tonnes of firewood used mainly for domestic heating.

Approximately 80 megalitres/yr ethanol produced.

Biodiesel production relatively low. Estimated to be below 20 million litres in 2002.

The Bureau of Rural Sciences has developed a bioenergy atlas for Australia.

Austria

Municipal solid waste		
quantity of raw material available	1.7	million tonnes
electricity generation	9 675	TJ
direct use from combustion	10 615	TJ
total energy production	20 290	TJ
Wood		
quantity of raw material available	4.4	million tonnes
electricity generation	54	TJ
direct use from combustion	64 737	TJ
total energy production	64 790	TJ

Other biomass		
quantity of raw material available	8.9	million tonnes
biodiesel capacity *	6 000	TJ/yr
direct use from combustion	42 093	TJ
total energy production	85 147	TJ

* Data refer to 2006

Being well-endowed with forests and therefore wood, Austria opted for energy produced from bioenergy, such as straw, rape and corn, in the early 1980s. This dominance of bioenergy-generated power is the result of a targeted research and development policy. Figures from the energy recycling agency show that for the past two decades, investment in this area has been higher than in other renewable energy sources.

Austria's long years of research and development have led E.V.A. (Austrian Energy Authority) experts to pronounce the country a world leader in biomass firing. Biomass furnaces, particularly when fuelled by new pellets, have successfully shown themselves to be the most environmentally friendly heating system on the market. This technological lead in wood-firing has created a rapidly growing export sector in Austria.

Belgium

Municipal solid waste		
quantity of raw material available	1.1	million tonnes
electricity generating capacity	76 600	kW
electricity generation	1 765	TJ
Black liquor/bark		
quantity of raw material available	0.2	million tonnes
electricity generating capacity	31 000	kW
electricity generation	585	TJ

Data refer to 1996

Bolivia

Animal dung		
direct use from combustion	3 270	TJ
Sugar cane bagasse		
direct use from combustion	10 458	TJ
Crop residues		
direct use from combustion	307	TJ

Data refer to 1996

Botswana

Municipal solid waste		
direct use from combustion	1 420	TJ

Estimated

Brazil

Municipal solid waste		
quantity of raw material available	23	million tonnes
electricity generating capacity	20 030	kW
electricity generation	505	TJ
total energy production	1 263	TJ
Sugar cane bagasse		
quantity of raw material available	106.47	million tonnes
electricity generating capacity	1 943	MW
electricity generation	27 585	TJ
direct use from combustion	885 491	TJ
total energy production	949 486	TJ
Wood		
quantity of raw material available	91.68	million tonnes
solid fuel production capacity	294 331	TJ/yr
yield of solid fuel	6.81	GJ/tonne
solid fuel production	267 574	TJ
electricity generating capacity	100 743	kW
electricity generation	2 224	TJ
direct use from combustion	674 889	TJ
total energy production	1 190	PJ
Forestry/wood processing		
quantity of raw material available	2.56	million tonnes
electricity generating capacity	102 569	kW
electricity generation	2 265	TJ
direct use from combustion	24 121	TJ
total energy production	28 945	TJ
Rice hulls		
quantity of raw material available	0.05	million tonnes
direct use from combustion	532	TJ
Black liquor		
quantity of raw material available	14.85	million tonnes
electricity generating capacity	730 918	kW
electricity generation	16 138	TJ
direct use from combustion	139 750	TJ
total energy production	177 808	TJ
Cane juice		
quantity of raw material available	106.47	million tonnes
ethanol production capacity	284 616	TJ/yr
yield of ethanol	2.55	GJ/tonne
ethanol production	271 063	TJ
total energy production	277 713	TJ
Molasses		
quantity of raw material available	12.52	million tonnes
ethanol production capacity	89 092	TJ/yr
yield of ethanol	6.78	GJ/tonne
ethanol production	84 849	TJ
total energy production	96 982	TJ

Bulgaria

Wood		
solid fuel production	30 019.4	TJ

The theoretical potential of biomass and waste amounts to 30 645 GWh/yr. The technical potential of biomass that can be utilised is about 10-25% of physical potential and varies between 3 064 and 7 660 GWh/yr.

Cameroon

Wood		
consumption for fuel	9 581	thousand tonnes
Charcoal		
consumption for fuel	138 952	tonnes
Sawdust and shavings		
consumption for fuel	175 383	tonnes

Canada

Municipal solid waste		
electricity generating capacity *	116 325	kW
Forestry/wood processing		
quantity of raw material available *	36.9	million tonnes
yield of solid fuel	18.5	GJ/tonne
solid fuel production	17 113	TJ
electricity generating capacity *	1 453	MW
electricity generation **	25 011	TJ
Crop residues - corn		
ethanol production capacity	3 658	TJ/yr
yield of ethanol	9.25	GJ/tonne
ethanol production	3 658	TJ
Crop residues – wheat		
ethanol production capacity	1 250.8	TJ/yr
yield of ethanol	8.85	GJ/tonne
ethanol production	1 250.8	TJ
Crop residues – wheat straw		
ethanol production capacity	23.6	TJ/yr
yield of ethanol	7.79	GJ/tonne
ethanol production	23.6	TJ
Canola		
biodiesel production capacity	147.6	TJ/yr
yield of biodiesel	16.79	GJ/tonne
biodiesel production	147.6	TJ
Fish oil		
biodiesel production capacity	258.3	TJ/yr
yield of biodiesel	41.7	GJ/tonne
biodiesel production	258.3	TJ

* Data refer to 2004
** Data refer to 2003

Canada has significant advantage in bioenergy, based on the extent of arable land and forested areas. Currently, biofuels, in the form of ethanol and biodiesel, are the most advanced source of bioenergy and the Federal Government has committed to ensuring that fuels sold in Canada have an average 5% renewable fuel content by 2010.

Installed ethanol capacity is 4 932 TJ/yr, of which corn-based ethanol accounts for approximately 74%, wheat-based ethanol contributes 25% and ethanol extracted from wheat straw less than 1%. Installed biodiesel capacity is 406 TJ/yr, of which canola-based biodiesel accounts for about 36% of Canadian production and fish oil for 64%.

Government support for alternative fuels includes exemption from the excise tax on gasoline, which equates to CDN$ 0.04/litre for biodiesel and CDN$ 0.10/litre for ethanol. The Ethanol Expansion Program provided support (CDN$ 100 million) to ethanol plants. Various research and development programs and public information programs are also supported, including the Canadian Biomass Innovation Network (CBIN) which coordinates R&D activities at the federal level in bioenergy, biofuels, and industrial biotechnology.

The following equipment qualifies for tax incentives with accelerated depreciation treatment: equipment powered by wood waste, municipal waste, biogas from a sewage treatment facility; equipment that recovers biogas from landfill sites; equipment used to convert biomass into bio-oil and biogas production equipment.

In 2005 around 35 million litres of ethanol were exported and 125 million imported. Of the 925 000 tonnes of wood pellets produced in 2005, 825 000 tonnes were exported (approximately 60% to Europe and 30% to the USA).

Cote d'Ivoire

As reported for SER 2004:

Data concerning the use of biomass energy (apart from wood and charcoal) are unavailable. To resolve this problem, a strategy is being devised to collect data on production and consumption of all forms of biomass.

There is a programme for restructuring the institutional framework of renewable energies and a project concerning the inventory and the evaluation of agricultural and industrial waste.

Natural biomass, agricultural waste and industrial waste constitute the potential renewable energies for direct use.

78% of the population consumes biomass energy in different forms (firewood, charcoal by city dwellers, agricultural and industrial waste).

The agricultural and industrial energy resources are estimated at more than 4 mtoe/yr. They constitute an important source of energy and essentially come from palm oil, manufactured wood, coffee, rice and sugar cane.

The principal technologies used for the conversion of biomass into energy are carbonisation, gasification and fermentation.

Firewood and charcoal constitute 60% of the national energy consumption. As well as household consumption, wood fuels are also used in restaurants, ironwork, bakeries, potteries, curing and drying feed.

Croatia

Wood		
solid fuel production capacity	112	TJ/yr
yield of solid fuel	28	GJ/tonne
solid fuel production	81.2	TJ
Forestry/wood processing		
solid fuel production capacity	60.5	TJ/yr
yield of solid fuel	17.2	GJ/tonne
solid fuel production	40.4	TJ

Czech Republic

Municipal solid waste		
quantity of raw material available	0.3	million tonnes
biogas production	532	TJ
electricity generation	320	TJ
direct use from combustion	1 386	TJ
total energy production	2 346	TJ
Forestry/wood processing		
quantity of raw material available	4.2	million tonnes
electricity generation	1 811	TJ
direct use from combustion	40 741	TJ
total energy production	46 174	TJ
Agricultural residues		
quantity of raw material available	1.4	million tonnes
biodiesel production capacity	8 190	TJ/yr
biodiesel production	5 300	TJ
biogas production	153	TJ
electricity generation	223	TJ
direct use from combustion	9 031	TJ
total energy production	15 000	TJ
Sewage sludge		
biogas production	1 650	TJ
electricity generation	266	TJ
direct use from combustion	851	TJ

In 2005 Czech Republic imported 8 000 tonnes of biodiesel and exported 132 000 tonnes.

Denmark

Municipal solid waste		
quantity of raw material available *	36 951	TJ
Wood		
quantity of raw material available	17 667	TJ

Forestry/wood processing		
quantity of raw material available	16 775	TJ
Agricultural residues - straw		
quantity of raw material available	1.275	million tonnes
Biodiesel		
production	2 670	TJ
Biogas		
production	3 830	TJ
Fish oil		
quantity of raw material available	0.02	million tonnes

* Comprising 28 695 TJ renewable waste and 8 256 TJ non-renewable waste.

In 2005 imports of wood and products from the forestry and wood-processing industry totalled 1 963 TJ and 1 199 TJ respectively; 2 670 TJ of biodiesel was exported.

Egypt (Arab Republic)

Municipal solid waste		
quantity of raw material available	2.4	million tonnes
Sugar cane bagasse		
quantity of raw material available	1.4	million tonnes
ethanol production capacity	456.25	TJ/yr
biodiesel production capacity	22.83	TJ/yr
total energy production	479.08	TJ
Forestry/wood processing		
quantity of raw material available	1.2	million tonnes
Cotton stalks		
quantity of raw material available	1.2	million tonnes
Rice straw		
quantity of raw material available	3.4	million tonnes
Animal dung		
quantity of raw material available	6	million tonnes
biogas production capacity	40	TJ/yr
yield of biogas	4.1	GJ/ tonne
biogas production	15	TJ
direct use from combustion	15	TJ
Sewage sludge		
quantity of raw material available	2.4	million tonnes
electricity generating capacity	18 000	kW
Industrial waste		
quantity of raw material available	3	million tonnes
Food processing waste		
quantity of raw material available	2	million tonnes

Data refer to 2002

Estonia

Municipal solid waste		
quantity of raw material available	0.569	million tonnes
biogas production (landfill gas)	107	TJ
Forestry/wood processing		
quantity of raw material available	0.567	million tonnes
solid fuel production	8 692	TJ

Data refer to 1999

Ethiopia

Sugar cane bagasse		
quantity of raw material available	0.75	million tonnes
ethanol production capacity	169	TJ/yr
ethanol production	148	TJ
direct use from combustion	7 568	TJ
total energy production	7 716	TJ
Wood		
quantity of raw material available	56	million tonnes
solid fuel production capacity	1 857	TJ/yr
yield of solid fuel	3.6	GJ/ tonne
solid fuel production	464	TJ
direct use from combustion	783 000	TJ
total energy production	783 464	TJ
Agricultural residues – crop residue		
quantity of raw material available	6.3	million tonnes
direct use from combustion	97 000	TJ
Agricultural residues – animal dung		
quantity of raw material available	9.8	million tonnes
biogas production capacity	3.7	TJ/yr
biogas production	1.5	TJ
direct use from combustion	136 000	TJ
total energy production	136 002	TJ

Finland

Municipal solid waste		
quantity of raw material available	1.2	million tonnes
electricity generation	2 160	TJ
direct use from combustion	2 380	TJ
total energy production	4 540	TJ
Wood		
direct use from combustion	48 280	TJ
Forestry/wood processing		
quantity of raw material available	17	million tonnes
solid fuel production capacity*	5 150	TJ/yr
yield of solid fuel*	17	TJ/ tonne
solid fuel production*	3 210	TJ

electricity generating capacity	2 000	MW
electricity generation	31 900	TJ
direct use from combustion	238 200	TJ
total energy production	273 310	TJ
Agricultural residues – reed canary grass		
quantity of raw material available**	0.05	million tonnes
direct use from combustion	750	TJ
Biogas from farm and co-digestion plants		
quantity of raw material available**	0.004	million tonnes
electricity generation	18	TJ
direct use from combustion	32	TJ
total energy production	50	TJ
Biogas from landfills		
quantity of raw material available**	0.2	million tonnes
electricity generation	34	TJ
direct use from combustion	1 046	TJ
total energy production	1 080	TJ
Biogas from wastewater treatment plants		
quantity of raw material available**	0.03	million tonnes
electricity generation	100	TJ
direct use from combustion	300	TJ
total energy production	400	TJ

* Data refer to 2004
** Data refer to 2002

The present use of bio-energy is dominated by residues and by-products from the forest industry. In 2005 the share of black liquor (and other similar liquors) was 39% of the total use of renewable energy (excluding peat). Wood fuels in industry and energy production also have a significant share (about 28%). The main part of forestry/wood processing residues is exploited by co-generation plants producing electricity and heat.

A substantial share, 83% (2 650 TJ), of Finnish wood pellets were exported.

The acreage of reed canary grass (grown as an energy crop) is increasing rapidly in Finland: in 2005 there were 10 400 ha under cultivation, rising to 16 000 ha in 2006. The crop can be harvested two years after seeding.

Biogas produced from 6 farm and 4 co-digestion plants totalled 2.702 million m^3, of which 90% was utilised as electricity (4.9 GWh), heat (8.4 GWh) and mechanical energy (0.02 GWh).

At the end of 2005 landfill gas was collected from 33 landfills and totalled 118.404 million m^3, of which 59% was utilised as electricity (9.5 GWh) and heat (289.0 GWh).

Biogas produced in 16 municipal and 4 industrial wastewater treatment facilities totalled 23.754 million m^3, of which 87% was utilised as electricity (27.7 GWh), heat (83.1 GWh) and mechanical energy (2.0 GWh).

France

Municipal solid waste		
quantity of raw material available	1 891	thousand toe
electricity generation	11 736	TJ
direct use from combustion	29 394	TJ
total energy production	41 130	TJ
Wood		
quantity of raw material available	7 419	thousand toe
direct use from combustion	310 559	TJ
Forestry/wood processing		
quantity of raw material available	1 935	thousand toe
electricity generation	4 888	TJ
direct use from combustion	4 748	TJ
total energy production	9 636	TJ
Agricultural residues – straw etc.		
quantity of raw material available	78	thousand toe
direct use from combustion	3 265	TJ
Biogas from landfills		
quantity of raw material available	127	thousand toe
electricity generation	1 422	TJ
direct use from combustion	251	TJ
total energy production	1 673	TJ
Biogas – other		
quantity of raw material available	82	thousand toe
electricity generation	234	TJ
direct use from combustion	2 093	TJ
total energy production	2 327	TJ
Biofuels		
quantity of raw material available	476	thousand toe
ethanol production	3 140	TJ
biodiesel production	16 785	TJ
total energy production	19 925	TJ

The above data relate only to metropolitan France and exclude overseas departments (DOM).

Sugar cane bagasse: in the DOM, the quantity of bagasse available in 2005 was 150 thousand toe; 1 494 TJ electricity was generated, 5 407 TJ was used directly from combustion and total energy production totalled 6 901 TJ.

Gabon

Sugar cane bagasse		
quantity of raw material available	113 490	tonnes

direct use from combustion	209 956.5	million kcal

Société Sucrière du Gabon, owner of the plantations, utilises the bagasse as a source of fuel for generating electricity and heat used in the transformation of the sugar cane.

Germany

Municipal solid waste *		
biodiesel production capacity	940 000	tonnes/yr
biogas production capacity	160	MW
biogas production	9 600	TJ
electricity generating capacity	852 000	kW
electricity generation	11 200	TJ
Forestry/wood processing**		
direct use from combustion	182 442	TJ
Wood waste etc. **		
electricity generation	639	GWh
Landfill gas **		
electricity generating capacity	142	MW
electricity generation	88	GWh
Sewage sludge gas **		
electricity generating capacity	75	MW
electricity generation	732	GWh
Liquid biofuels **		
plant capacity	500 000	tonnes/yr
Other biogas **		
electricity generating capacity	200	MW
electricity generation	74	GWh

* Data refer to 2002
** Data refer to 2001

Ghana

Agricultural residues		
quantity of raw material available		
coconut shell and husk	0.135	million tonnes
groundnut shells	0.0475	million tonnes
rice straw and husk	0.120	million tonnes

Data refer to 1990

Greenland

Municipal solid waste		
solid fuel production capacity	214	TJ/yr
yield of solid fuel	10.5	GJ/tonne

solid fuel production	281	TJ
direct use from combustion	83	TJ
Waste from fishing industry		
yield of biodiesel	38.62	GJ/tonne
biodiesel production	12.33	TJ

Data refer to 2002

Hong Kong, China

Municipal solid waste		
quantity of raw material available	7.7	million tonnes
Sewage gas		
direct use from combustion	116.2	TJ
Landfill gas		
quantity of raw material available	240	million m^3
biogas production capacity	350	TJ/yr
yield of biogas	0.005	GJ/ tonne
biogas production	72	TJ
electricity generation	14	TJ
direct use from combustion	2 000	TJ
total energy production	2 086	TJ

In May 2005, the Hong Kong Government established a renewable energy strategy in its First Sustainable Development Strategy for Hong Kong. The strategy aims for 1-2% of total power generation to come from renewables by the year 2012. This would be met through a combination of wind power, solar energy and waste-to-energy. Municipal solid waste could make a significant contribution to this goal.

Hong Kong's comprehensive Policy Framework for the Management of Municipal Solid Waste (2005-2014) outlines a plan for reducing waste, increasing recycling and recovery, and treating about half of the remaining waste by incineration and/or other methods. These could include waste-to-energy.

A demonstration waste-to-energy facility was operated by Green Island Cement in 2005. This facility combined waste and fuel oil to produce electricity for on-site use.

Of approximately 240 million cubic metres of landfill gas available in Hong Kong in 2005, about 130 million cubic metres were utilised as energy. The unused gas was flared.

In 2005, the major uses of landfill gas in Hong Kong were heating up leachate in the ammonia removal process for the treatment of landfill waste water on-site, and generating electricity for the landfill site infrastructures, such as offices, maintenance workshop and pumping stations.

However, landfill gas was also used in a variety of other ways: as fuel in the production of town gas, and for power generation supplied to the grid; gas from a closed landfill (containing 14.3 million tonnes of waste, including construction and demolition waste) was treated and piped to the gas company where it was used as fuel to provide 72 TJ of energy in the town gas production process. Landfill gas was also used to generate 14 TJ (4 Gigawatt hours) of electricity for the Hong Kong power grid.

Hungary

Municipal solid waste		
quantity of raw material available	0.258	million tonnes
yield of solid fuel	12.5	GJ/ tonne
solid fuel production	19 908	TJ
biodiesel production capacity	114	TJ/yr
yield of biodiesel	38	GJ/ tonne
biogas production capacity	133	TJ/yr
yield of biogas	23	GJ/ tonne
biogas production	100	TJ
electricity generating capacity	26 064	kW
electricity generation	290	TJ
direct use from combustion	32 141	TJ
Forestry/wood processing		
quantity of raw material available	1.167	million tonnes
Agricultural residues		
quantity of raw material available	0.175	million tonnes

Data refer to 2002

Iceland

Municipal solid waste		
electricity generating capacity	831	kW
electricity generation	15	TJ
direct use from combustion	56	TJ
total energy production	71	TJ

The total quantity of municipal waste is in the region of 0.5 million tonnes.

Electricity generation from landfill gas began in 2004.

Indonesia

Sugar cane bagasse		
quantity of raw material available	6.5	million tonnes
Agricultural residues - rice husk		
quantity of raw material available	14.3	million tonnes
Agricultural residues - coconut shells		
quantity of raw material available	1.1	million tonnes
Agricultural residues - coconut fibre		
quantity of raw material available	2.0	million tonnes

Agricultural residues - palm oil residues		
quantity of raw material available	8.5	million tonnes

Data refer to 1999

Iran (Islamic Republic)

Municipal solid waste		
quantity of raw material available	15.33	million tonnes
Forestry/wood processing		
quantity of raw material available	0.2	million tonnes

Data refer to 1999

Ireland

Municipal solid waste		
electricity generating capacity	14 732	kW
electricity generation	324	TJ

Data refer to 1999

Israel

Municipal sewage		
electricity generating capacity	2 000	kW
electricity generation	5 000	MWh
Industrial waste water		
electricity generating capacity	300	kW
electricity generation	1 000	MWh

Italy

Municipal solid waste		
electricity generating capacity	526 500	kW
electricity generation	9 431	TJ
direct use from combustion	11 957	TJ
total energy production	21 388	TJ
Wood		
electricity generating capacity *	389 400	kW
electricity generation	42 070	TJ
direct use from combustion	106 925	TJ
total energy production	148 995	TJ
Agricultural residues – wine, beet molasses, corn and fruits		
ethanol production capacity **	281 000	tonnes/yr
ethanol production	127 200	tonnes/yr
Agricultural residues – oil seeds, fatty acid		
biodiesel production capacity	857 000	tonnes/yr
biodiesel production	396 000	tonnes
direct use from combustion	15 000	tonnes
Agricultural residues – oil seeds		
quantity of raw material available	0.79	million tonnes

Other – animal, human and industrial organic waste		
biogas production ***	14 382	TJ
electricity generating capacity	283 873	kW

* Installed capacity is powered by solids and other agro-industrial waste

** Production of ETBE

*** Used to make electricity

Japan

Municipal solid waste		
quantity of raw material available *	601	thousand toe
electricity generating capacity **	1 553 000	kW
Sugar cane bagasse		
quantity of raw material available *	80	thousand toe
electricity generating capacity ***	27 000	kW
Wood		
quantity of raw material available *	438	thousand toe
electricity generating capacity ***	50 000	kW
Agricultural residues – rice husk		
quantity of raw material available *	6	thousand toe
Black liquor		
quantity of raw material available *	4 032	thousand toe

* Data relate to FY 1999

** Data relate to 2004.3

*** Data relate to 2000.3

Jordan

Municipal solid waste		
quantity of raw material available	2	million tonnes
biogas production	3.6	million m^3
electricity generating capacity	1 000	kW
electricity generation	5 142	MWh
direct use from combustion	5 142	MWh

Jordan has executed a pilot project for the utilisation of municipal solid waste for electricity generation through landfill and biogas technology systems. The project is funded by GEF and is considered to be the first of its kind in the region, with a capacity of 1 MW. A biogas company was established to run this plant. During 2006 the capacity of the plant was increased to 3.5 MW and is expected to generate 28 GWh/yr.

Korea (Republic)

Municipal solid waste		
direct use from combustion	21 153	TJ

Sugar cane bagasse		
biodiesel production	561	TJ
Wood		
solid fuel production	250	TJ
direct use from combustion	11 970	TJ
total energy production	12 220	TJ
Landfill gas		
electricity generating capacity	30 293	kW
electricity generation	1 356	TJ
direct use from combustion	428	TJ
total energy production	1 784	TJ
Sludge gas		
direct use from combustion	1 161	TJ
Other gas		
direct use from combustion	672	TJ

Latvia

Municipal solid waste		
quantity of raw material available	0.3	million tonnes
yield of biogas	7.3	GJ/tonne
biogas production	127	TJ
electricity generating capacity	7 300	kW
electricity generation	120	TJ
Wood		
yield of solid fuel	12.6	GJ/tonne
solid fuel production	59 500	TJ
Agricultural residues – corn		
ethanol production capacity	260	TJ/yr
yield of ethanol	26	GJ/tonne
ethanol production	260	TJ
Agricultural residues – canola		
biodiesel production capacity	93.5	TJ/yr
yield of biodiesel	37.4	GJ/tonne
biodiesel production	93.5	TJ

Wood occupies a central place in Latvia's energy resources as 45% of the territory is covered by forests.

In 2005 11.29 million m^3 of trees were felled, of which 3.89 million m^3 (34.5%) were from government forests and 7.4 million m^3 (65.5%) from forests belonging to private owners, municipalities and others. In contrast to the year 2001, the total felled wood has increased by 0.78 million m^3. This rise can be attributed to an increase of 0.69 million m^3 trees cut in privately-owned forests. The comparable rise in timber harvested from government-owned forests was only 0.09 million m^3.

The quantity of felling allowed from sustainable forest supplies has been increased to 10 million m^3/yr, a level exceeded in each year between 1999 and 2006.

A thriving industry utilising waste wood exists in Latvia: more than 30 companies are engaged in the production of woodchip briquettes, which are mainly exported to the Nordic countries; a great number of small companies are using wood waste for the production of charcoal and, being in high demand within Europe, it is both exported and sold locally; wood pellets produced are mostly exported. In 2005 20.3 PJ of wood pellets, charcoal and woodchips were exported to the UK and Scandinavian countries.

Lebanon

Municipal solid waste		
quantity of raw material available	1.44	million tonnes

Data refer to 2001

In 2004, it was reported that biogas projects were installed on a small, trial scale. None were designed to generate electricity but rather provide heating fuel. Plant residues are generally burnt in rural homes for space heating.

Lithuania

Wood		
quantity of raw material available	2.05	million tonnes
electricity generating capacity	1 500	kW
electricity generation	9.4	TJ
direct use from combustion	29 641	TJ
total energy production	29 650	TJ
Agricultural residues – straw		
quantity of raw material available	0.02	million tonnes
direct use from combustion	112	TJ
Agricultural residues – rape-grain		
quantity of raw material available	0.02	million tonnes
biodiesel production capacity	370	TJ/yr
yield of biodiesel	12.4	GJ/tonne
biodiesel production	260	TJ
Agricultural residues – rye-wheat corn		
quantity of raw material available	0.02	million tonnes
ethanol production capacity	590	TJ/yr
yield of ethanol	12.4	GJ/tonne
ethanol production	270	TJ

According to recent data from the Forest Inventory and Management Institute, Lithuania's forested land area is about 32% of the territory or about 20.9 thousand km^2. In 2005 the total consumption of firewood and wood waste was assessed as 3 616 thousand m^3 or 708.7 thousand toe, the major share of which was firewood (569.3 thousand toe) used directly by final consumers and 144.2 thousand toe for production of heat in heating plants.

On 5 December 2001 the Government of Lithuania approved a regulation No 1474 *Procedure for the Promotion of Purchasing of Electricity Generated from Renewable and*

Waste Energy Sources. The regulation promotes the use of biofuels for power generation and feed-in tariffs (€ 0.0579/kWh) are applied for the purchase of electricity generated by such power plants.

Production of biofuels (used as motor fuels) is increasing in Lithuania. In 2006, capacities of AB 'Biofuture' will increase from 16 000 to 21 000 tonnes of dehydrated ethyl alcohol (ethanol). A new company is being formed which will significantly increase capacity for the production of biodiesel (methyl ester from rape-seed oil) and vegetable oils. There are plans to process 300 000 tonnes of rape-seed and to produce about 115 000 tonnes of methyl ester.

Luxembourg

Wood		
solid fuel production	700	TJ
Agricultural residues		
biogas production	226	TJ
Municipal waste residue		
solid fuel production	1 730	TJ

Data refer to 2004

Mexico

Municipal solid waste		
quantity of raw material available	160	million tonnes
electricity generating capacity	7 400	kW
electricity generation	186.7	TJ
Sugar cane bagasse		
quantity of raw material available	13	million tonnes
total energy production	92 063	TJ
Wood		
quantity of raw material available	17.8	million tonnes
total energy production	258 411	TJ
Forestry/wood processing		
quantity of raw material available	1.32	million tonnes
total energy production	23 760	TJ
Agricultural residues – pig farms *		
quantity of raw material available	15.6	million tonnes
biogas production capacity	26 408	TJ/yr
yield of biogas	1.69	GJ/ tonne
Agricultural residues – milk dairies *		
quantity of raw material available	36.6	million tonnes
biogas production capacity	30 281	TJ/yr
yield of biogas	0.84	GJ/ tonne
Agricultural residues – slaughter houses *		
quantity of raw material available	84.1	million tonnes

biogas production capacity	530	TJ/yr
yield of biogas	0.006	GJ/ tonne
Recycled waste water		
quantity of raw material available	1.6	million tonnes
biogas production capacity	38.5	TJ/yr
yield of biogas	0.024	TJ/yr
biogas production	33.7	TJ
electricity generating capacity	971	kW
electricity generation	14.5	TJ
total energy production	48.2	TJ
Animal fat (biodiesel)		
quantity of raw material available	0.006	million tonnes
Biodiesel production capacity	252	TJ/yr
yield of biodiesel	46.7	GJ/ tonne
biodiesel production	95	TJ

* Data refer to potential identified resources: no installations have yet been built.

Monaco

Municipal solid waste		
quantity of raw material available	0.07	million tonnes
electricity generating capacity	2 600	kW
electricity generation	26	TJ
direct use from combustion	72	TJ
total energy production	98	TJ

Data refer to 1996

Morocco

Animal dung		
biogas production capacity	4.00	TJ/yr
yield of biogas	0.56	GJ/tonne
biogas production	4.00	TJ

Data refer to 1996

Namibia

At the present time there is no legislation in place to regulate the use of bio-energy resources.

Nepal

Wood		
direct use from combustion	293.17	TJ
Agricultural residues		
direct use from combustion	14.3	TJ
Animal dung		
direct use from combustion	21.63	TJ

Netherlands

Municipal solid waste		
electricity generation	10 296	TJ
direct use from combustion	1 085	TJ
total energy production	11 381	TJ
Forestry/wood processing		
direct use from combustion		
households	5 400	TJ

industry	1 750	TJ
Landfill gas		
biogas production	2 763	TJ
Sludge		
biogas production	2 041	TJ
Fermentation		
biogas production	5 632	TJ

Data refer to 1999

New Zealand

Forestry/wood processing		
quantity of raw material available	43 540	TJ
electricity generating capacity	78 573	kW
electricity generation	1 900	TJ
direct use from combustion	35 419	TJ
total energy production	37 319	TJ
Sewage		
quantity of raw material available	470	TJ
electricity generating capacity	5 950	kW
electricity generation	99	TJ
direct use from combustion	115	TJ
total energy production	214	TJ
Landfill		
quantity of raw material available	1 049	TJ
electricity generating capacity	16 000	kW
electricity generation	294	TJ

Paraguay

Sugar cane bagasse		
quantity of raw material available	0.536	million tonnes
ethanol production capacity *	861.6	TJ/yr
yield of ethanol *	1.303	GJ/tonne
ethanol production **	704.231	TJ
Wood		
quantity of raw material available	4.417	million tonnes
yield of solid fuel	10.501	GJ/tonne
solid fuel production	6 746.3	TJ
direct use from combustion	56 854.52	TJ
total energy production	63 600.82	TJ
Forestry/wood processing		
quantity of raw material available	1.319	million tonnes
direct use from combustion	24 066.79	TJ
Agricultural residues – cotton		
quantity of raw material available	0.263	million tonnes
direct use from combustion	3 844.1	TJ

Agricultural residues - other		
quantity of raw material available	0.062	million tonnes
direct use from combustion	940.9	TJ

* Data refer to total (i.e. including non-energy use)

** Data refer to energy use

Peru

Sugar cane bagasse		
quantity of raw material available	1.9	million tonnes
electricity generating capacity	43 400	kW
electricity generation	5 003.6	TJ
direct use from combustion	2 475.2	TJ
total energy production	7 478.8	TJ
Wood		
quantity of raw material available	5.13	million tonnes
yield of solid fuel	15.1	GJ/tonne
solid fuel production	5 697.6	TJ
direct use from combustion	71 335.4	TJ
total energy production	77 033.0	TJ
Agricultural residues		
biogas production capacity	15.07	TJ/yr
yield of biogas	13.5	GJ/tonne
biogas production	10.55	TJ

Philippines

Municipal solid waste		
electricity generation	6	TJ
Sugar cane bagasse		
electricity generation	6 518	TJ
Forestry/wood processing		
electricity generation	22 981	TJ
Crop residues - coconut		
electricity generation	7 046	GWh
Crop residues – rice		
electricity generation	2 934	GWh
Animal		
electricity generation	146	GWh

Data refer to 2002

Poland

Municipal solid waste		
direct use from combustion	675	TJ
Wood / Forestry/wood processing		
quantity of raw material available	13 839	thousand m^3
direct use from combustion	127 914	TJ
total energy production	131 474	TJ

Agricultural residues		
direct use from combustion	21 337	TJ
total energy production	31 741	TJ
Industrial waste		
direct use from combustion	16 529	TJ
total energy production	22 282	TJ

The Polish Statistical Office does not currently publish data on itemised bioenergy by type. The following total bioenergy production data are available for 2005:

Solid fuels (biomass and industrial wastes)	49.3	PJ
Liquid biofuels	0.6	PJ
Biogas	2.0	PJ
Electricity	1 506	MWh

Up to the present time renewable energy has not been intensively utilised. However, this situation is likely to change considerably in the short term, owing to European law and Poland's renewable energy obligations. By 2010, it is expected that electricity generation from renewables (geothermal, biomass, wind and hydro) will contribute 9% of the total. Moreover, the share of biofuels in the transport sector will rise to 5.75%.

Portugal

Municipal solid waste		
quantity of raw material available	1.1	million tonnes
electricity generating capacity	90 000	kW
electricity generation	7 919	TJ
Forestry/wood processing		
quantity of raw material available	6.2	million tonnes
biogas production	424	TJ
electricity generating capacity	369 000	kW
electricity generation	8 757	TJ
direct use from combustion	104 906	TJ
total energy production	113 663	TJ

Romania

Municipal solid waste		
quantity of raw material available	545	thousand toe
Wood		
quantity of raw material available	487	thousand toe
Forestry/wood processing		
quantity of raw material available	1 175	thousand toe
Agricultural residues		
quantity of raw material available	4 799	thousand toe

Biogas		
quantity of raw material available	588	thousand toe

Russian Federation

Forestry/wood processing		
quantity of raw material available	73.7	million GJ
electricity generating capacity	560.4	MW
electricity generation	2.2	TWh
direct use from combustion	40.7	million GJ

Data refer to 2001

Senegal

Municipal solid waste		
electricity generating capacity	20 000	kW
Agricultural residues – peanut shells		
electricity generating capacity	22 000	kW
Biomass potential (per annum)		
Peanut shells	197 500	tonnes (221 MW)
Palmetto shells	1 740	tonnes
Sugar cane bagasse	250 000	tonnes (20 MW)
Rice husks	217 212	tonnes
Sawdust	3 000	cubic metres
Millet/Sorghum/Maize stalks	4 052 900	tonnes
Typha reed	1 000 000	tonnes
Cotton stalks	23 991	tonnes
Peanut haulm	790 617	tonnes

Data refer to 1999

Serbia

Municipal solid waste		
quantity of raw material available	31 200	TJ
Forestry/wood processing		
quantity of raw material available	2 300	TJ
direct use from combustion	3 300	TJ
Agricultural residues		
quantity of raw material available	56 200	TJ
Orchard		
quantity of raw material available	14 100	TJ
Vineyard		
quantity of raw material available	6 100	TJ

Singapore

Municipal solid waste		
electricity generating capacity	135 000	kW
electricity generation	3 994.68	TJ

Data refer to 2002

Slovakia

Wood		
quantity of raw material available	0.4	million tonnes
Forestry/wood processing		
quantity of raw material available	1.4	million tonnes
Agricultural residues - straw		
quantity of raw material available	0.73	million tonnes
Agricultural residues – corn		
quantity of raw material available	0.67	million tonnes
Agricultural residues – other		
quantity of raw material available	0.63	million tonnes
Dung		
quantity of raw material available	13.7	million tonnes

Slovenia

Landfill		
electricity generating capacity	253	kW
electricity generation	29.936	TJ
Urban sewage sludge		
electricity generating capacity	31	kW
electricity generation	2.232	TJ
Solid biomass		
electricity generation	81.555	TJ
direct use from combustion	19.560	TJ

In 2005 cumulative biodiesel capacity totalled 24 000 tonnes/yr and production 8 700 tonnes.

South Africa

Sugar cane bagasse		
quantity of raw material available *	3.6	million tonnes
Wood		
quantity of raw material available *	11.2	million tonnes
Forestry/wood processing		
quantity of raw material available *	8.1	million tonnes

* Calculated from a TJ value, using conversion factors of 14 MJ/kg for bagasse and 17 MJ/kg for fuel wood and forestry wastes.
Data generally refer to 2003

A data collection system for biofuels has not yet been formalised in South Africa.

Spain

Agricultural residues		
quantity of raw material available	5 768 563 *	toe
ethanol production capacity	415 000	tonnes/yr
ethanol production	257 000	tonnes
biodiesel production capacity	322 000	tonnes/yr
biodiesel production	150 000	tonnes

* Potential = 12 802 208 toe

The breakdown of bioenergy electricity generation capacity is not available. Total installed electricity generating capacity stood at 3 440 kW at end-2004 and provisionally at 3 660 kW at end-2005.

In 2004 the total direct and indirect energy produced from all bioenergy sources was 4 167 035 toe.

The estimated potential of forestry/wood processing residues is of 11 819 000 toe, but at end-2004 only 7 576 040 toe were being exploited.

Sri Lanka

As preliminary steps towards eventual large-scale use of wood for electricity generation, two facilities have been installed in Sri Lanka:

- in the village of Endagalayaya, a 3.5 kW_e electrical generator coupled with a gasifier system processing chips of Gliricidia Sepium; this provides lighting for 31 houses, with each having 2 light bulbs indoors and one externally to deter elephants and other wild animals;
- at Walapane, a 1 MW_e dendro-thermal power plant fuelled by Gliricidia wood, and capable of generating 6 447 MWh/yr.

Gliricidia Sepium is a fast-growing tropical tree cultivated by local farmers.

A biomass gasifier at Madampe, in the Coconut Triangle, also uses wood as feedstock. The gas is used to dry coconut fibre prior to its conversion into briquettes, which are then exported for use as a growing medium

Swaziland

Sugar cane bagasse		
quantity of raw material available	1.32	million tonnes
Forestry/wood processing		
quantity of raw material available	0.63	million tonnes

Data refer to 2002

Sweden

Municipal solid waste		
solid fuel production	12 300	TJ
biogas production	1 250	TJ

electricity generating capacity	290	kW
electricity generation	9 400	TJ
Wood		
solid fuel production	330 000	TJ
electricity generating capacity	2 500	kW
electricity generation	53 000	TJ

Switzerland

Municipal solid waste		
quantity of raw material available	3.25	million tonnes
electricity generating capacity	301 600	kW
electricity generation	3 079.8	TJ
direct use from combustion	8 386.0	TJ
total energy production	11 465.8	TJ
Sewage		
electricity generation	406.5	TJ
direct use from combustion	1 001.0	TJ
total energy production	1 407.5	TJ
Wood (incl. forestry/wood residues)		
electricity generation	118.8	TJ
direct use from combustion	19 610.0	TJ
total energy production	19 728.8	TJ
Manure and vegetal residues		
electricity generation	33.9	TJ
direct use from combustion	17.1	TJ
total energy production	51.0	TJ

Syria (Arab Republic)

Municipal solid waste		
quantity of raw material available	4	million tonnes
Wood		
quantity of raw material available	0.5	million tonnes
Forestry/wood processing		
quantity of raw material available	0.2	million tonnes

Taiwan, China

Municipal solid waste		
electricity generating capacity	583.8	kW
electricity generation	27 128.9	TJ
Waste cooking oil		
quantity of raw material available	0.15 – 0.2	million tonnes
biodiesel production capacity	275.97	TJ/yr
yield of biodiesel	34.5	GJ/tonne
biodiesel production	5.2 – 6.9	GJ

Tanzania

Sugar cane bagasse		
quantity of raw material available	229 617	tonnes
Wood		
quantity of raw material available	140	million m^3

The country has a considerable biomass resource in the form of agricultural and forest residues and animal wastes which together account for about 90% of the nation's energy requirements. There is no immediate renewable energy substitute for wood fuel used for cooking apart from biogas, the technology of which has not yet reached a high enough level of dissemination.

According to data for 2003, there was a growing stock of 4.39 billion m^3 woody biomass with a mean annual increment of 140 million m^3. Annual wood fuel consumption is approximately 34 million m^3, contributing to deforestation at an estimated rate of 91 276 ha/yr.

Generally, biomass is not internationally traded.

The Government has formed a National Taskforce to work on liquid fuels promotions. The Taskforce/Special Committee is working in close collaboration with various stakeholders to formulate practical recommendations. The production of ethanol and biodiesel is being developed by small-scale private companies.

Thailand

Municipal solid waste		
electricity generating capacity	3 125	kW
electricity generation	43	TJ
Agricultural residues – molasses		
quantity of raw material available	1.16	million tonnes
ethanol production capacity	2 597	TJ/yr
yield of ethanol	5.24	GJ/tonne
ethanol production	1 146	TJ
Agricultural residues – waste water		
biogas production capacity	26.98	million m^3/yr
yield of biogas	0.497	ttoe/m^3
biogas production	8.691	ttoe
Agricultural residues – waste from farm		
biogas production capacity	16.41	million m^3/yr
yield of biogas	1.2	kWh/m^3
biogas production	33.174	GWh
Agricultural residues – used cooking oil		
quantity of raw material available	0.08	million tonnes
biodiesel production capacity	65.3	TJ/yr
yield of biodiesel	33	GJ/tonne
biodiesel production	42	TJ

In 2005 there was a total molasses production of 2.26 million tonnes. The domestic consumption (excluding the ethanol industry) was about 1.1 million tonnes. There was thus 1.16 million tonnes available for export or ethanol production. Thailand imported about 20.9 million litres (438 TJ) of ethanol.

Turkey

Municipal solid waste		
quantity of raw material available	~ 25	million tonnes
biogas production	~ 575	TJ
Sugar cane bagasse		
quantity of raw material available	N	million tonnes
Wood		
quantity of raw material available	3.52	million tonnes
Forestry/wood processing		
quantity of raw material available	3.56	million tonnes
Agricultural residues – straw + stalks		
quantity of raw material available	13.2	million tonnes
Agricultural residues – kernels, shells, tree prunings		
quantity of raw material available	4	million tonnes
Dung		
quantity of raw material available	13.8	million tonnes

Biodiesel can be produced under the biodiesel processing licence, given by the Energy Market Regulatory Body (EMRA). Currently, 52 biodiesel production companies have applied to the EMRA.

There is only one bioethanol production plant in Turkey, mostly processing wheat. The total production capacity of the plant is 30 000 m^3/yr.

The Turkish bioenergy resource is in the form of agricultural crops and residues, including dry manure, but have yet to be properly determined. The results above are taken from the final report of a project founded by European Commission (EC Contract Number: LIFE 03 TCY/TR/000061), *Exploitation of Agricultural Residues in Turkey*.

Ukraine

Agricultural residues – wheat, corn, barley etc.		
quantity of raw material available	4.27	million tonnes
direct use from combustion	64	TJ
Agricultural residues – sunflower		
quantity of raw material available	1.21	million tonnes

direct use from combustion	38.3	TJ
Wood		
quantity of raw material available	0.33	million tonnes
direct use from combustion	23	TJ
Dung		
quantity of raw material available	0.74	million tonnes
biogas production	10.9	TJ
Sewage sludge		
biogas production	105.5	TJ

In 2005 the use of biogas at the Bortnychy cleaning facility (Kiev) saved over 2.3 million m^3 of natural gas (equal to about 3.6 thousand tce).

United Kingdom

Municipal solid waste *		
quantity of raw material available	3.7	million tonnes
electricity generating capacity	321 400	kW
electricity generation	5 551	TJ
direct use from combustion	6 255	TJ
total energy production	11 806	TJ
Wood & forestry/wood processing		
quantity of raw material available	1.1	million tonnes
direct use from combustion	11 937	TJ
Agricultural residues **		
quantity of raw material available	1.1	million tonnes
electricity generating capacity	186 100	kW
electricity generation	3 078	TJ
direct use from combustion	3 094	TJ
total energy production	6 172	TJ
Biomass co-fired with fossil fuels		
quantity of raw material available ***	2	million tonnes
electricity generating capacity	308 800	kW
electricity generation	9 112	TJ
Landfill gas		
electricity generating capacity	817 800	kW
electricity generation	15 444	TJ
Sewage sludge digestion		
electricity generating capacity	127 900	kW
electricity generation	1 440	TJ

* Including non-biodegradable wastes, which account for about 40% of the total.

** Includes farm waste, poultry litter, meat and bone, straw and energy crops.

*** In 2005, of the 2 million tonnes of biomass used for co-firing, 1.8 million was imported and 0.2 was home produced.

In 2005 consumption of biodiesel and bioethanol was almost all from imported sources, but amounts were comparatively small.

The UK also used landfill gas and sewage gas for the production of heat and electricity and classifies these as biofuels.

The White Paper *Meeting the Energy Challenge* (May 2007) announced the Government's intention to strengthen the Renewables Obligation (RO), increasing the RO to 'up to 20% as and when increasing amounts of renewables are deployed' and introducing banding of the RO in order to provide differentiated support to the various renewable technologies. In this latter connection, particular mention was made of the need to bring forward offshore wind and biomass.

United States of America

Municipal solid waste		
quantity of raw material available	146.2	million tonnes
electricity generating capacity*	2 647	MW
electricity generation*	53 580	TJ
direct use from combustion	23 940	TJ
total energy production	77 520	TJ
Forestry/wood processing		
quantity of raw material available	153	million tonnes
electricity generating capacity	6 970	MW
electricity generation	139 252	TJ
direct use from combustion	975 817	TJ
total energy production	1 115	PJ
Agricultural residues – corn		
ethanol production	313 051	TJ
Agricultural residues – soybean		
biodiesel production	11 331	TJ
Agricultural residues – other		
electricity generating capacity	282 700	kW
electricity generation	2 430	TJ
direct use from combustion	37 631	TJ
total energy production	40 061	TJ
Landfill gas		
electricity generating capacity	963 000	kW
electricity generation	18 487	TJ
direct use from combustion	67 005	TJ
total energy production	85 492	TJ
Other		
electricity generating capacity	359 300	kW
electricity generation	4 803	TJ
direct use from combustion	9 958	TJ
total energy production	14 760	TJ

In 2005, 8 847 TJ of ethanol was imported.

Uruguay

Municipal solid waste		
biogas production capacity	31.5	TJ/yr

electricity generating capacity	1 000	kW
Sugar cane bagasse		
quantity of raw material available	0.05	million tonnes
electricity generating capacity	3 000	kW
electricity generation	20.9	TJ
direct use from combustion	502.1	TJ
Wood		
quantity of raw material available	1.5	million tonnes
electricity generating capacity	2 800	kW
electricity generation	33.5	TJ
direct use from combustion	16 769.5	TJ
Agricultural residues – sunflower husks		
quantity of raw material available	0.03	million tonnes
direct use from combustion	37.7	TJ
Agricultural residues – rice husks		
quantity of raw material available	0.24	million tonnes
electricity generation	4.2	TJ
direct use from combustion	748.9	TJ
Black liquor		
quantity of raw material available	0.04	million tonnes
electricity generation	58.6	TJ
direct use from combustion	447.7	TJ

In March 2006 the Government passed a decree which is the first stage in encouraging the installation of up to 20 MW of electricity generation based on biomass (<10 MW) provided by IPPs.

10. Solar Energy

COMMENTARY

COMMENTARY

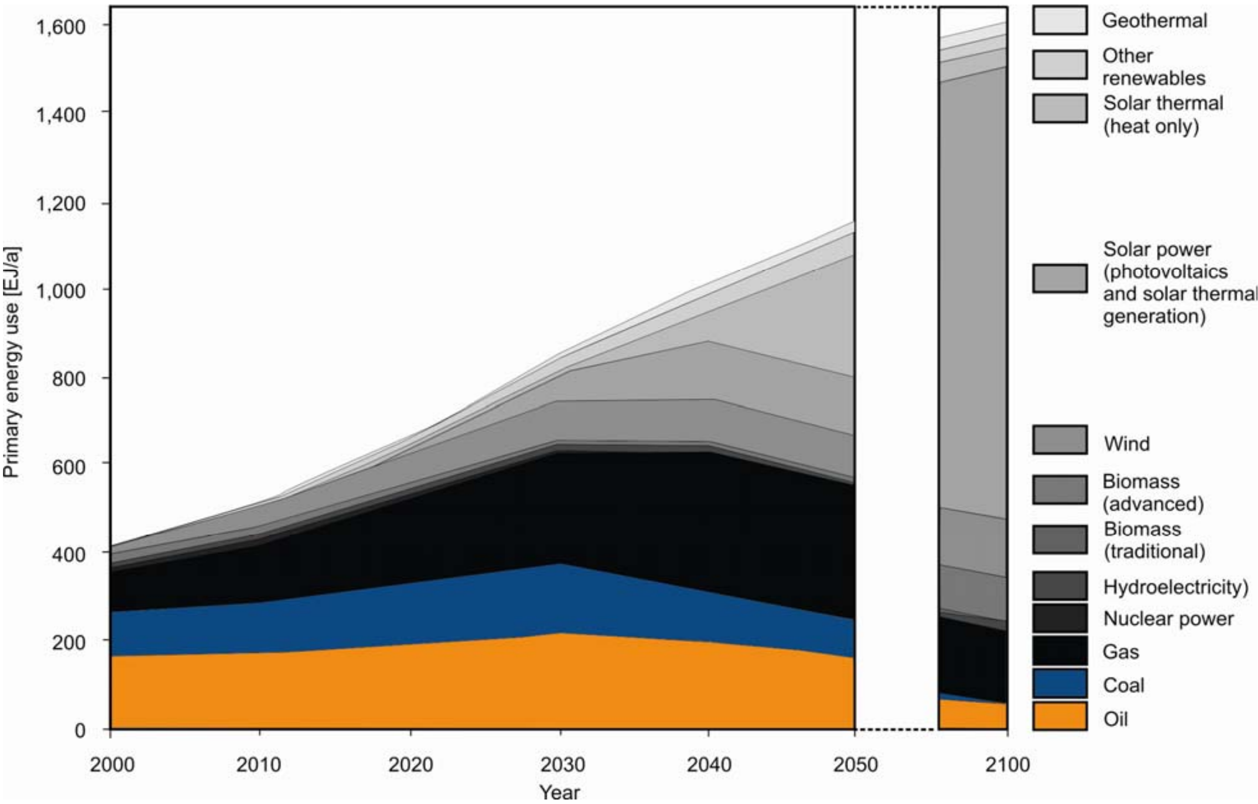
Introduction

Solar energy is the most abundant permanent energy resource on earth and it is available for use in its direct (solar radiation) and indirect (wind, biomass, hydro, ocean etc.) forms. This commentary is limited to the direct use of solar radiation, the earth's prime energy resource.

The Sun emits energy at a rate of 3.8×10^{23} kW. Of this total, only a tiny fraction, approximately 1.8×10^{14} kW is intercepted by the earth, which is located about 150 million km from the sun. About 60% of this amount or 1.08×10^{14} reaches the surface of the earth. The rest is reflected back into space and absorbed by the atmosphere. Even if only 0.1% of this energy could be converted at an efficiency of only 10% it would be four times the world's total generating capacity of about 3 000 GW. Looking at it another way, the total annual solar radiation falling on the earth is more than 7 500 times the world's total annual primary energy consumption of 450 EJ.

The annual solar radiation reaching the earth's surface, approximately 3 400 000 EJ, is an order of magnitude greater than all the estimated (discovered and undiscovered) non-renewable energy resources, including fossil fuels and nuclear. However, 80% of the present worldwide energy use is based on fossil fuels. Several risks are associated with their use. Energy infrastructures - power plants, transmission lines and substations, and gas and oil pipelines - are

Figure 10-1 Transforming the global energy mix: the exemplary path to 2050/2100
Source: WBGU, 2003

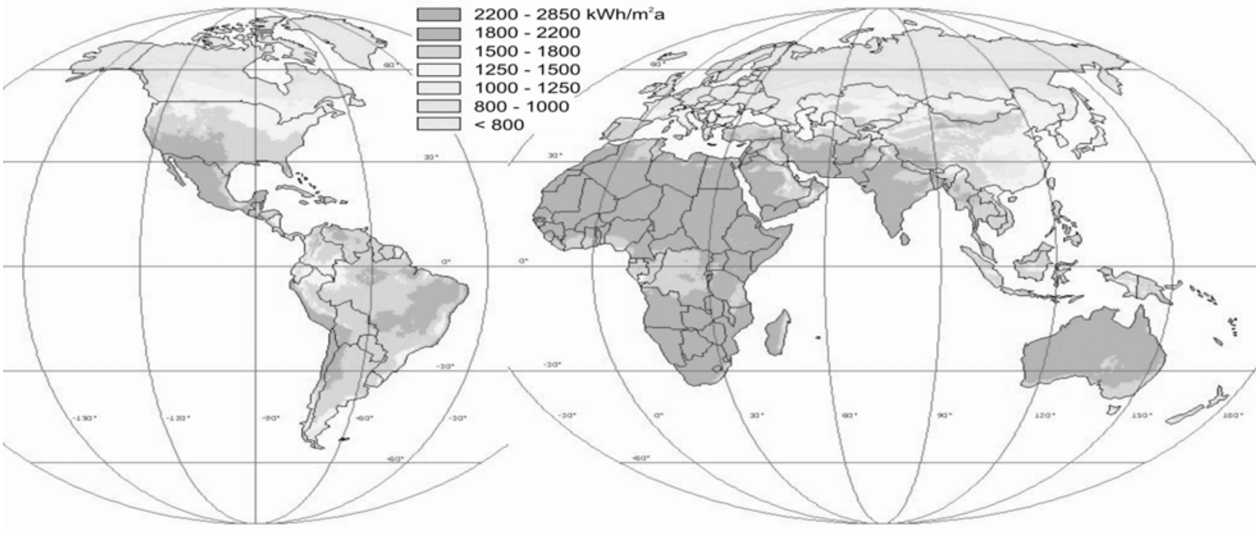


all potentially vulnerable to adverse weather conditions or human acts. During the summer of 2003, one of the hottest and driest European summers in recent years, the operations of several power plants, oil and nuclear, were put at risk owing to a lack of water to cool the condensers. In other parts of the world, hurricanes and typhoons put the central fossil and nuclear power plants at risk. World demand for fossil fuels (starting with oil) is expected to exceed annual production, probably within the next two decades. Shortages of oil or gas can initiate international economic and political crises and conflicts. Moreover, burning fossil fuels releases emissions such as carbon dioxide, nitrogen oxides, aerosols, etc. which affect the local, regional and global environment.

Concerns regarding present energy systems are therefore growing because of the inherent risks connected with security of supply and potential international conflicts, and on account of the potential damage they can do to the natural environment in many and diverse ways. World public opinion, international and national institutions, and other organisations are increasingly aware of these risks, and they are pointing to an urgent need to fundamentally transform present energy systems onto a more sustainable basis.

A major contribution to this transformation can be expected to come from solar radiation, the prime energy resource. In several regions of the world the seeds of this possible transformation can be seen, not only at the technological level, but also at policy levels. For example, the European Union has recently announced policies and plans to obtain 20% of its energy needs through renewable energy by 2020. The German Advisory Council on Global Change (WBGU) recently conducted an analysis of energy needs and resources in the future to the years 2050 and 2100 (Fig. 10-1) which points to a major contribution by solar energy to global energy needs in the long term. This scenario is based on the recognition that it is essential to move energy systems towards sustainability worldwide, both in order to protect the natural life-support systems on which humanity depends and to eradicate energy poverty in developing countries. Of course, this new solar era can be envisioned mainly because of the tremendous scientific and technological advances made

Figure 10-2 Average yearly solar radiation, mean values 1981-2000
Source: Energie-Atlas GmbH



during the last century and the ongoing research and development.

By 2100 oil, gas, coal and nuclear, as shown in Fig. 10-1, will provide less than 15% of world energy consumption while solar thermal and photovoltaic will supply about 70%. Key elements of this long-term scenario are the energy efficiency and energy intensity policies that will make the contribution of renewable and solar energy a substantial factor. Those policies will deeply transform the building and construction, industry and transport sectors, increasing their reliance on renewable energy resources.

The transition towards this possible future has already started. In the following paragraphs an attempt will be made to show this by reviewing the state of the art regarding solar radiation resource assessment and the status and rate of growth of the major solar energy technologies, their technical and market maturity as well as institutional and governmental policies and approaches to promote their integration into the world's energy systems.

Solar Radiation Resources

The amount of solar radiant energy incident on a surface per unit area and per unit time is called irradiance or insolation. The average extraterrestrial irradiance or flux density at a mean earth–sun distance and normal to the solar beam is known as the *solar constant*, which is 1 367 W/m^2 according to the most recent estimate. The energy delivered by the sun is both intermittent and changes during the day and with the seasons. When this power density is averaged over the surface of the earth's sphere, it is reduced by a factor of 4. A further reduction by a factor of 2 is due to losses in passing through the earth's atmosphere. Thus, the annual average horizontal surface irradiance is approximately 170 W/m^2. When 170 W/m^2 is integrated over 1 year, the resulting 5.4 GJ that is incident on 1 m^2 at ground level is approximately the energy that can be extracted from one barrel of oil, 200 kg of coal, or 140 m^3 of natural gas.

However, the flux changes from place to place. Some parts of the earth receive much higher than this annual average. The highest annual mean irradiance of 300 W/m^2 can be found in the Red Sea area, and typical values are about 200 W/m^2 in Australia, 185 W/m^2 in the United States and 105 W/m^2 in the United Kingdom. These data show that the annual solar resource is almost uniform (within a factor of about 2), throughout almost all regions of the world. It has already been shown that economically attractive applications of solar energy are not limited to just the sunniest regions. Northern European countries offer good examples of this.

Figs. 10-3 to 10-5 show the daily solar energy falling on the Earth in the months of December, April and June.

In a period of rapidly growing deployment of solar energy systems, it is imperative that solar

Figure 10-3 Average daily solar radiation for December

Source: NASA/SSE

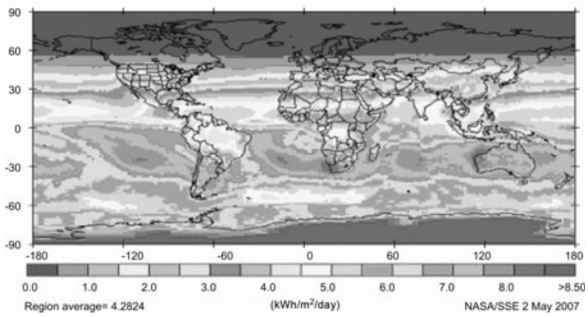
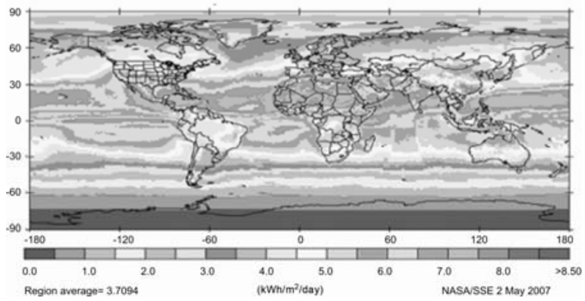


Figure 10-4 Average daily solar radiation for April

Source: NASA/SSE



resource parameters and their space/time specificity be well known to solar energy professionals, planners, decision makers, engineers and designers. Because these parameters depend on the applications (flat solar thermal collectors, solar thermal power plants, photovoltaic, window glass, etc.), they may differ widely, and might be unavailable for many locations, given that irradiance measurement networks or meteorological stations do not provide sufficient geographically time/site-specific irradiance coverage. This coverage is especially useful because it allows assessment of the output of a solar system in relation to the technical characteristics of the system, local geography and energy demand. It therefore allows a better assessment of the feasibility of a solar energy application and of its value.

Measured solar radiation data are available at a number of locations throughout the world. Data

for many other locations have been estimated, based on measurements at similar climatic locations. The data can be accessed through internet web sites of national government agencies for most countries in the world. Worldwide solar radiation data are also available from the World Radiation Data Center (WRDC) in St. Petersburg, Russia. WRDC, operating under the auspices of the World Meteorological Organization (WMO) has been archiving data from over 500 stations and operates a web site in collaboration with the National Renewable Energy Laboratory (NREL) (http://wrdc-mgo.nrel.gov). Other sources of data are given in the references at the end of this commentary. Most recently, methods are being developed to convert measurements made by satellites to solar radiation values on the ground. Once these methods are developed and validated, they will be able to provide solar radiation data for any location in the world.

Solar Collectors

Solar thermal collectors are used to heat air, water or other liquids, depending on the applications, while solar photovoltaic (PV) collectors are used to convert sunlight to electricity directly. High-temperature solar thermal collectors are also used to produce electricity indirectly via thermodynamic cycles. Non-concentrating (or flat-plate) types of solar collectors can produce temperatures of about 100°C or less, which is applicable for many uses such as building heating and cooling, domestic hot water and industrial process heat. Medium-temperature concentrating collectors such as parabolic troughs or parabolic dishes may be used to provide temperatures from about 100°C to about 400°C. Such collectors may be used for various applications from refrigeration to industrial process heat and electricity generation. Central-receiver types of solar concentrating collectors are able to produce temperatures as much as 2 000°C or even higher. Therefore, they are used to produce electrical power and as high-temperature furnaces in industrial processes.

PV panels are solid-state and are therefore very rugged, with a long life. At present, panels based on crystalline and polycrystalline silicon

Figure 10-5 Average daily solar radiation for June
Source: NASA/SSE

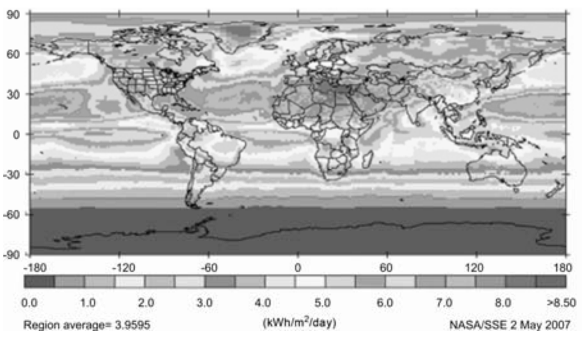
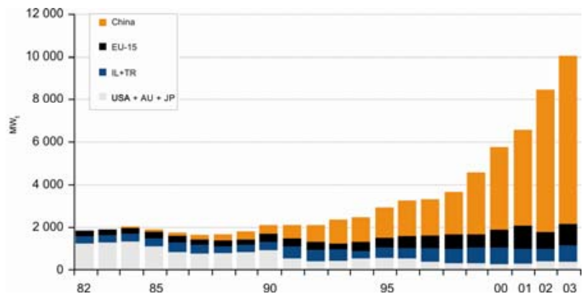


Figure 10-6 Production of solar thermal collectors in the world
Sources: IEA SHC, ESTIF



solar cells are the most common. Their efficiencies have gradually increased, while costs have decreased over the last three decades. For example, the efficiencies of multijunction cells and concentrating PV have been reported to be as high as 40%, and most panels available in the market have efficiencies of the order of 15%. The retail price of PV panels came down from about US$ 30/W about 30 years ago to about US$ 3/W some 3 years ago. The price went up recently, owing to a very rapid increase in demand which created a temporary shortage of silicon wafers. While this situation has created opportunities for investments in silicon wafer production which will bring supply into line with demand, it has also created opportunities for companies to start production of thin-film solar cells based on cadmium telluride (CdTe) and copper indium diselenide (CIS), which use much less material and therefore have the potential to ultimately bring the cost of PV panels down to about US$ 1/W.

To evaluate the efficiency of solar energy systems, a standard flux of about 1 000 W/m^2 is used, which is approximately the solar radiation incident on a surface directly facing the sun on a clear day around noon. Consequently, solar systems are rated in terms of *peak watts* (output under a 1 kW/m^2 illumination).

Solar Energy Applications

The energy in solar radiation can be used directly or indirectly for all of our energy needs in daily life, including heating, cooling, lighting, electrical power, transportation and even environmental cleanup. Many such applications are already cost-competitive with conventional energy sources, for example, photovoltaic (PV) electricity in remote applications is replacing diesel generator sets. Some applications, such as photovoltaics and solar heating are better known and popular, while others such as solar detoxification of contaminated waters or solar distillation are less known.

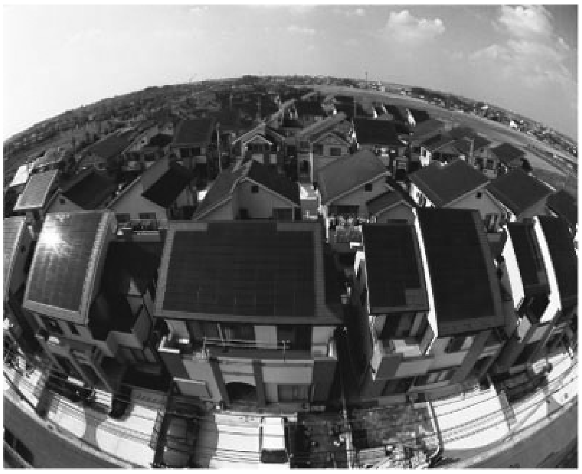
Solar water heating is the most developed solar technology and is very cost-effective when life-cycle costs are considered. However, the initial costs (capital investment) of solar water heaters are many times higher than those for electric water heaters. Therefore, most people opt for electric water heaters. In many countries, governments have adopted policies and financing mechanisms that make it easier for consumers to buy solar water heaters. For this reason the adoption of solar water heating worldwide is growing at a rate of more than 20% per year, as shown in Fig. 10-6. Growth in China has been even greater, at around 27% per year.

Adoption of solar water heating can have a great impact on the reduction of peak electrical load and thus greenhouse gas emissions. For example, if all the electric water heaters in the USA (approximately 100 million) were replaced by solar water heaters, it would reduce the peak load by about 100 GW.

Solar Industrial Process Heat (SIPH) is an ideal application of solar energy. As a matter of fact, 30-50% of the thermal energy needed in industrial processes is below 250°C, which can

Figure 10-7 An example of Building Integrated Photovoltaics
Source: Goswami

Figure 10-8 The Japanese Cosmotown Kiyomino SAIZ housing development
Source: Goswami



be easily provided by low- and medium-temperature solar collectors. Consequently, this application of solar energy is expected to grow as the cost of fossil fuels goes up.

In industrialised countries, 35-40% of total primary energy consumption is used in buildings. However, if the energy used to manufacture materials and the infrastructure to serve the buildings is taken into account then buildings' share of total primary energy consumption can be around 50%. In Europe, 30% of energy use is for space and water heating alone, representing 75% of total energy use in buildings.

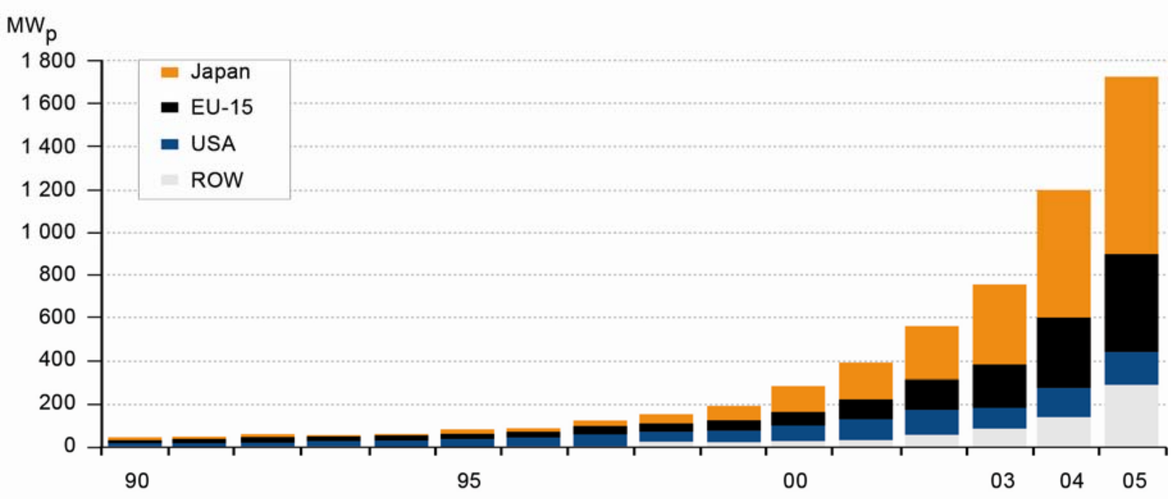
Solar technologies can make a substantial contribution to the energy budget of modern buildings, and consequently to the world's energy use. Buildings can be the largest collectors of solar energy and therefore the electrical appliances (light bulbs, refrigerators, washing machines, etc.) with innovative energy-efficient models, can reduce electricity demand and increase the significance of, e.g.

photovoltaic electricity, to the whole energy budget. Passive solar building designs can reduce the conventional energy consumption by as much as 75% and PV can provide the rest. Such designs use knowledge of the position of the sun either to allow sunlight to enter the building for heating or to shade the building for cooling, and employ natural ventilation and daylighting. There is thus a growing trend towards passive solar and Building Integrated Photovoltaics (BIPV) designs. In BIPV designs, PV panels replace some other component of the building such as roof shingles, wall panels or window shades etc. PV manufacturers are developing very attractive patterns, colours and designs of panels, and architects are integrating them into buildings, making them look even more attractive. These PV panels consequently become much more cost-effective than they otherwise would. Fig. 10-7 shows an example of a PV integrated building.

Globally, about 8–10 million new buildings are constructed every year, most of them in developing countries. Large areas of these countries do not have access to grid electricity, thus making solar energy an attractive alternative. Even if only a tiny fraction of these buildings were served by solar, the implications for the solar and energy industry could be enormous, not only from a technological point of view but also from a cultural point of view. It would be a contributory factor to changing the way people think about conventional sources of energy and solar energy.

Even though solar building applications can be cost-effective, they may not happen without appropriate policy intervention. New regulations and building codes, regarding energy-saving measures and the integration of energy-efficient and solar technologies in buildings, will be necessary to accelerate the deployment of solar energy. Such policy intervention has been the

Figure 10-9 Worldwide production of photovoltaic panels
Source: EPIA - P. Maycock



secret behind several success stories in the use of solar thermal collectors: for example, the 1980 regulation in Israel requiring every new building with a height of less than 27 m to have a solar thermal system on its roof. Similar regulations adopted over the last few years by a number of large and small towns elsewhere have stimulated a significant growth in solar thermal installations.

Because buildings do not exist in isolation, the ‘whole building’ approach can be extended to blocks of buildings or to towns, as in the photovoltaic application shown in Fig. 10-8. This depicts Cosmotown Kiyomino SAIZ, a complex of 79 homes built by the Hakushin Company, with the Kubota Corporation supplying a roof-integrated 3 kW photovoltaic power generation system for each house. This illustration also underlines an argument, often raised against solar energy utilisation: namely land usage. Solar energy is often seen as a ‘dispersed’ source of energy compared with concentrated fossil fuels and nuclear energy. This argument is misleading because the solar energy systems installed on walls and roofs in Kiyomino do not use land additional to that used for the construction of the buildings themselves. Moreover, land usage for fossil-fuel infrastructures for transportation, distribution and waste storage can be considerable.

The extension of solar energy use from a block of solar buildings to an entire city is possible. There are several cities around the world that are working in this direction, aiming at greater use of solar energy within the context of a long-term plan for sustainable urban development. Such projects focus on cities as complete systems, in which passive solar heating and cooling, daylighting, solar photovoltaic, and solar thermal technologies are integrated.

In the following paragraphs the most widely used solar systems for the production of electricity, heat and fuels are reviewed.

Solar Photovoltaic Systems (PV)

Photovoltaic conversion is the direct conversion of sunlight into electricity with no intervening heat engine. As indicated above, photovoltaic devices are rugged and simple in design and require very little maintenance. Perhaps the biggest advantage of solar photovoltaic devices is that they can be constructed as stand-alone systems to give outputs from microwatts to megawatts. That is why they have been used as the power sources for calculators, watches, water pumping, remote buildings, communications, satellites and space vehicles, and even megawatt-scale power plants. With such a vast array of applications, the demand for photovoltaics is increasing every year. In 2005, over 1 700 MW_p of photovoltaic panels were sold for terrestrial uses and the market is growing at a phenomenal rate: about 35% per year worldwide (Fig. 10-9).

In the early days of solar cells in the 1960s and 1970s, more energy was required to produce a

Figure 10-10 World record efficiencies of various PV technologies

Source: Goswami

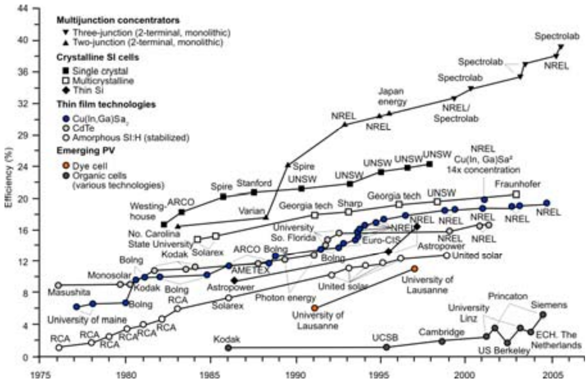
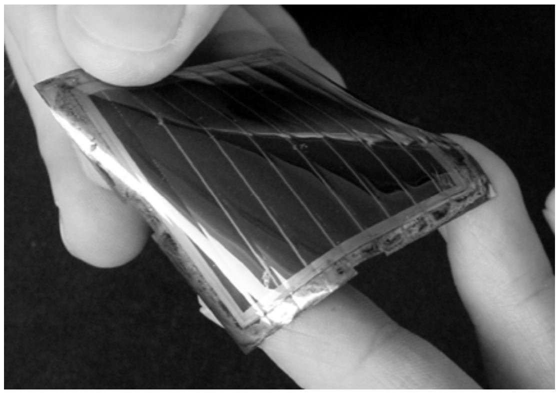


Figure 10-11 Flexible monolithic CIGS prototype mini-module on a polymer foil

Source: Goswami



cell than it could ever deliver during its lifetime. Since then, dramatic improvements have taken place in their efficiency and manufacturing methods. The energy payback period has been reduced to about 2-4 years, depending on the location of use, while panel lifetime has increased to over 25 years. The energy payback period of multijunction thin-film Concentrating PV is projected to be less than one year. As mentioned above, the cost of photovoltaic panels has come down. The current US$ 3/W cost of solar panels results in system costs of US$ 5-7/W which is very high for on-grid applications. Perhaps however, these dollar costs do not adequately portray the true environmental value of solar PV systems. Even at an energy payback period of 3 years and a lifetime of 25 years, the return on energy investment is more than 8:1 and return on CO_2 avoidance is more than 6:1.

The limits imposed on the efficiency of solar cells due to band gap can be partially overcome by using multiple layers of solar cells stacked on top of each other, each layer with a band gap higher than the layer below it. The efficiency would increase with the number of layers. However, for this concept to work the thickness of each layer must be extremely small; this has been achieved by the development of Thin-Film PV technologies. Some of the materials being developed for thin-film solar cells include cadmium telluride (CdTe), copper indium diselenide (CIS), copper indium gallium diselenide (CIGS), gallium arsenide (GaAs) and indium phosphide (InP). Of these, CdTe and CIS are receiving the most commercial attention at this time. Multijunction thin-film solar cells give even higher efficiencies when exposed to concentrated sunlight. Therefore, a great deal of commercial attention is being focused on Concentrating Photovoltaics or CPV.

The current state of solar cell development is illustrated in Fig. 10-10. While crystalline and polycrystalline silicon solar cells dominate today's solar industry, the rapid rise in efficiency vs time (experience curve) of the multijunction thin-film cells makes this a particularly attractive technology path.

Under concentrated sunlight, multijunction (GaInP/GaAs/Ge [germanium]) solar cells have demonstrated efficiencies twice (39.3%) that of most silicon cells. This means that, in sunny areas, a multijunction concentrator system can generate almost twice as much electricity as a silicon panel with the same cell area. The concentrating optics focus the light onto a small area of cells, reducing the area of the solar cells by a factor of, typically 500-1 000 times. The reduced cell area overcomes the increased cell cost. The cell cost is diminished in importance and is replaced by the cost of optics. If the cost of the optics is comparable to the cost of the glass and support structure needed for silicon flat-plate modules, then the cost per unit area can remain fixed while the electricity production is essentially doubled. Thus, in high direct insolation locations, multijunction concentrator technology has the potential to reduce the cost of solar electricity by about a factor of two. The efficiency is a moving target; today's triple-

Figure 10-12 Flow diagram for a typical solar thermal power plant
Source: Goswami

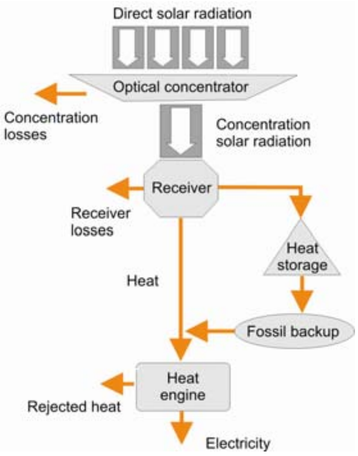
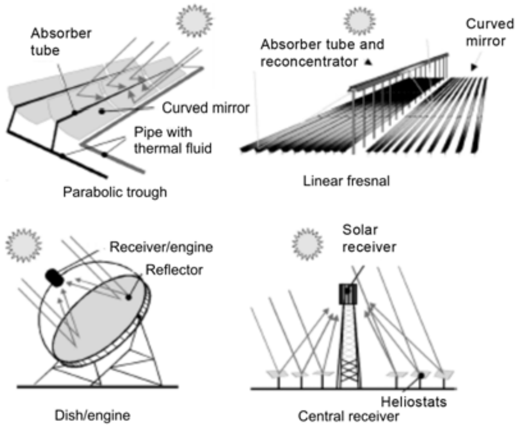


Figure 10-13 Schematic diagrams of the four types of Concentrating Solar Power (CSP) systems
Source: Goswami



junction cell efficiency is nearly 40%. Thus it may be reasonably extrapolated that multijunction cells may reach 50% efficiency in the future.

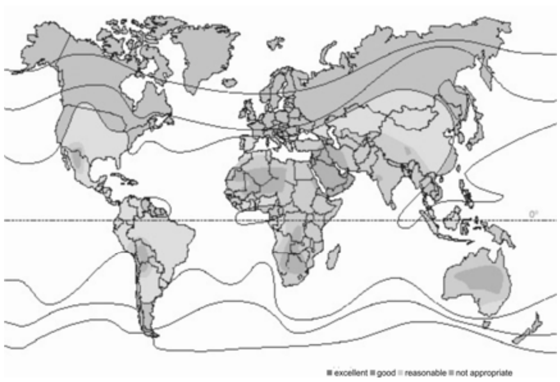
The biggest advantage of solar PV systems is that they can provide from a few watts to hundreds of megawatts. Development of flexible thin-film PV panels (Fig. 10-11) makes them ideal for integration in building design. In this way, they can utilise the solar exposure provided by the buildings and therefore not use any extra land.

Solar Thermal Power Plants

Concentrating solar collectors can achieve temperatures in the range of 300^{0}C to 1 000^{0}C or even higher, which is ideal for generating electricity via thermodynamic power cycles. All of the present power plants based on fossil fuels and nuclear power work on the same principles. Therefore this technology takes advantage of the knowledge base relating to conventional power plants. Another advantage of Solar Thermal Power is that it can easily use fossil fuels such as natural gas as a back-up fuel or store high-temperature heat to overcome the disadvantage of the intermittency of sunlight. Fig. 10-12 explains the concept of a solar thermal power plant operating with storage and/or a backup fuel. Fig. 10-13 shows schematic diagrams of the types of concentrating solar collector used for solar thermal power plants.

Solar thermal power plants use direct sunlight, so they must be sited in regions with high direct solar radiation, as those shown in Fig. 10-14.

Figure 10-14 Regions of the world appropriate for Concentrating Solar Power (CSP)
Source: European Commission



Among the most promising areas are the south-western United States, Central and South America, Africa, the Middle East, the Mediterranean countries of Europe, south Asia, certain countries of the Former Soviet Union, China and Australia.

CSP capacity of 364 MW was installed in California in 1990 (Figs. 10-15 and 10-16), most of which (354 MW) is still operating. Each year the performance of the plant has improved, due to the learning experience and better operations and maintenance procedures. This power plant is based on parabolic-trough technology, with natural gas as a backup fuel. Although investments in new solar power plants ceased

Figure 10-15 Parabolic-trough based solar thermal power plant in California (parabolic trough collectors [left]; power plant [right])
Source: Goswami

for a while because of a lack of R&D and favourable policies, recently there has been a resurgence of interest in this technology. A number of plants are under construction or in the planning stage around the world, which when completed, will increase worldwide capacity to about 3 000 MW. Of this, more than 2 000 MW will be in Spain, because of the excellent solar resource and favourable government policies.

Figure 10-16 Central receiver power plant in California
Sorce: Goswami

The reported capital costs of Solar Thermal Power plants have been in the range of US$ 3 000-3 500/kW, although lower costs are being quoted now. These costs result in a price of electricity of US$ 0.10-0.14/kWh. Based on ongoing research and development, the capital costs are expected to decrease to US$ 1 500-2 000/kW, which will bring solar thermal power closer to conventional power, even without considering the environmental costs/benefits.

A new generation of solar power systems is under development in various parts of the world. Trough technology with direct steam generation is under experimentation at the Plataforma Solar de Almería, part of the Centro de Investigaciones Energéticas Medioambientales y Tecnológicas (CIEMAT) on Spain's Mediterranean coast. Much the greater part of the research and commercial activity on solar thermal power is happening in Spain.

Solar Energy Storage Systems

As a result of solar energy's intermittent nature, the growth in worldwide usage will be constrained until reliable and low-cost technology for storing solar energy becomes available. The sun's energy is stored on a daily basis by nature through the process of photosynthesis in foodstuffs, wood and other biomass. The storage of energy from intermittent and random solar radiation can be achieved artificially, by using energy storage technologies (thermal storage, chemically-charged batteries, hydro storage, flywheels, hydrogen, and compressed air), some well-known and widely-applied, whilst others are still under development.

Thermal storage for solar heat and chemically-charged batteries for off-grid PV systems are the most widely used solar energy storage systems today. However, there are many who think that hydrogen produced using solar energy will provide the long-term solution for solar energy storage and much research is being undertaken around the world. Only the future will tell

Strong public policies and political leadership are needed to move forward the application of solar and other renewable energy technologies.

whether hydrogen will become cost-effective as compared with other storage options.

Other Solar Energy Applications

Availability of drinking water is expected to be the biggest problem to face mankind over the next few decades. Even though there is an abundant water resource in the oceans, it must be desalinated before use. Solar energy can play a very important role in this application. Although simple solar desalination and distillation technology has been known for a long time, there has not been much research to improve the technology for large-scale use.

Other lesser known applications of solar energy include its environmental applications such as solar photocatalytic detoxification and disinfection. This application has been shown to clean contaminated ground water and industrial waste water. It can also be used to disinfect water for potable use.

Conclusion and Outlook

Great advances have been made in the development of solar energy technologies. Efficiencies have been improved and costs have been brought down by orders of magnitude. The technologies have become cost-effective for some applications. However, they are still too expensive for other applications such as grid electricity, unless environmental costs are accounted for or incentives are given for these technologies.

At present, the markets for solar PV technologies are increasing at a rate of more than 35% per year and solar thermal power growth is expected to be even higher. However, these applications are starting from a very small or negligible base. Therefore, an even higher growth rate would be needed to reach the levels envisioned for the future. Strong public policies and political leadership are needed to move forward the application of solar and other renewable energy technologies, while maintaining robust research efforts to advance present technologies and develop new ones.

Countries whose governments have established firm goals for the penetration of renewable energy into primary energy and electricity generation, or have adopted specific policy mechanisms, are achieving great success. Examples are the successful feed-in laws adopted in several European countries, for instance, Germany and Spain; the Renewables Portfolio Standard (RPS) adopted by several of the American states, which ensures that a minimum amount of renewable energy is included in the portfolio of electricity production; and city ordinances requiring solar systems to be used for water heating in residential and commercial buildings. Appropriate policy measures have shown that solar applications can be boosted with many positive side effects, from the creation of new industries, new jobs and new economic opportunities, to the protection of the environment.

Energy conservation - through improvements in energy efficiency and decreases in energy intensity - is essential to increase the fractional contribution of renewable energy while meeting the energy needs of society.

Based on a review of the ongoing research in solar energy technologies, it is clear that they will continue to improve, promising higher efficiencies and lower costs. Examples of such promising new technologies beyond the horizon include continued development of new thin-film technologies, nano-scale antennas for conversion of sunlight to electricity, biological nano-scale PV, new concepts in solar desalination, visible light photocatalytic technologies for PV or environmental applications, and new thermodynamic cycles for solar thermal power. These developments are expected to help achieve the projected solar energy penetration levels by 2050 and beyond. However, in the meantime, it is essential to adopt policies that will ensure accelerated deployment of the present solar energy technologies.

D. Yogi Goswami

Past President, ISES;

Editor-in-Chief, Solar Energy Journal

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TABLES

TABLE NOTES

At this point in time, the quantification of solar energy in terms of installed capacity and annual output of electricity and heat presents extraordinary difficulties, which are probably greater than those encountered with any other source of energy. The combination of comparatively newly-developed technologies, rapid market growth and widespread, virtually worldwide, diffusion (often at the level of individual households, many in remote rural areas) makes comprehensive enumeration extremely difficult, if not impossible. This means that any aggregate data on a national level can be no more than indicative of the situation.

Table 10-1 provides data on photovoltaic generating capacity and annual output in 2005, as available from the following sources:

- WEC Member Committees, 2006/7;
- *Trends in Photovoltaic Applications: Survey report of selected IEA countries between 1992 and 2005*, International Energy Agency – Photovoltaic Power Systems Programme, August 2006.

Table 10-1 Solar Energy: photovoltaic capacity and output at end-2005

	Installed capacity (kW_p)	Annual output (MWh)
Africa		
Algeria	2 800	3 000
Egypt (Arab Rep.)	4 500	9 034
Ethiopia	2 940	
Gabon		63
Guinea	148	
Namibia	700	307
South Africa		21 000
Tanzania	1 200	
North America		
Canada	16 770	
Mexico	18 650	34 036
United States of America	496 000	
South America		
Argentina	9 000	14 000
Brazil	15 000	
Peru	3 714	3 110
Uruguay	80	
Asia		
Bangladesh	3 500	
China	70 000	
Hong Kong, China	> 800	200
India	85 000	
Japan	1 421 908	2 258 720
Korea (Republic)	13 524	14 399
Malaysia	3 000	
Nepal	3 328	
Sri Lanka	1 051	1 135
Taiwan, China	1 000	
Thailand	23 700	
Turkey	500	
Europe		
Austria	24 000	13 000
Croatia	49	50
Czech Republic	100	68
Denmark	2 700	2 160
Finland	4 000	2 500
France	33 570	35 385

Table 10-1 Solar Energy: photovoltaic capacity and output at end-2005

	Installed capacity (kW_p)	Annual output (MWh)
Germany	1 429 000	
Hungary	100	150
Italy	34 000	31 000
Latvia	3	3
Luxembourg	23 600	19 000
Netherlands	50 776	
Norway	7 252	
Portugal	2 280	3 000
Romania	90	65
Russian Federation	N	N
Slovakia	60	10
Slovenia	216	
Spain	51 900	57 000
Sweden	4 237	
Switzerland	26 300	19 300
United Kingdom	10 900	8 000
Middle East		
Iran (Islamic Rep.)	300	230
Israel	1 044	
Jordan	500	
Oceania		
Australia	60 581	

Note:

1. The data shown above constitute a sample, reflecting the information available in particular countries: they should not be considered as complete, or necessarily representative of the situation in each region. For this reason, regional and global aggregates have not been computed.
2. The data for France include French Overseas Departments (DOM)

COUNTRY NOTES

The Country Notes on Solar Energy have been compiled by the Editors. In addition to national, international, governmental publications/web sites and direct personal communications, the following publications have been consulted:

- *Photovoltaic Power Systems Programme, Annual Reports 2005 and 2006,* International Energy Agency;
- *Trends in Photovoltaic Applications: Survey report of selected IEA countries between 1992 and 2005,* International Energy Agency – Photovoltaic Power Systems Programme, August 2006;
- *Solar Thermal Markets in Europe (Trends and Market Statistics 2005),* European Solar Thermal Industry Federation, June 2006;
- *PV Status Report 2006*, European Commission, Joint Research Centre, August 2006.

Information provided by WEC Member Committees has been incorporated as available.

Albania

Most of the country receives a level of insolation of more than 1 500 kWh/m^2/yr, within a range of 1 185 to 1 690 kWh/m^2/yr. The western, and especially the southwestern, region of Albania has a particularly significant solar resource.

In 2005, some 32 000 m^2 of solar water heating systems were in service, of which approximately 18 000 m^2 were in the commercial sector and 14 000 m^2 in the residential sector. Output totalled in the region of 45 GWh (25 GWh commercial, 20 GWh residential).

In September 2006 various schemes to encourage the development of the solar thermal market were either being planned or at least considered: incentives in the form of tax credits or soft loans; the encouragement of an SWH manufacturing industry, Government co-financing incentives, legislation for the installation of solar thermal systems in new buildings, etc.

Algeria

Algeria receives an average insolation of 2 000 h/yr, with the high plateaux and the Sahara receiving 3 900 h/yr. The average solar energy received is 2 400 kWh/m^2/yr, ranging from 1 700 kWh/m^2/yr in the north of the country to 2 263 kWh/m^2/yr in the south.

Whilst the share that solar power contributes to the overall supply of energy is small, it has proved invaluable for the electrification of isolated settlements, especially in the south of the country. Rural PV electrification programmes accord priority to regions that are sparsely populated and situated far from the grid. The

Algerian WEC Member Committee reports that at end-2005 approximately 1.4 MW_p of photovoltaic capacity had been installed for this purpose. In addition, PV systems provided power for water pumping (0.4 MW_p), public lighting (0.2 MW_p), telecommunications (0.5 MW_p) and other uses (0.2 MW_p). Total output from PV devices is reported to have been approximately 3 000 MWh in 2005.

Argentina

Argentina's PAEPRA (Programa de Abastecimiento Eléctrico a la Población Rural de Argentina) was established in 1995 and the PERMER (Proyecto de Energía Renovable en el Mercado Eléctrico Rural) project was subsequently designed to support it.

The main development goal of PERMER is to improve the quality of life of rural inhabitants who have not been reached by the Electric Transformation Programme. It will aim to achieve this objective through:

- provision of an electricity service that meets the basic needs of lighting and social communication, with decentralised supply sources based on technologies mainly using renewable resources;
- promotion of the participation of the private sector in the provision of this supply so as to achieve the sustainability of the project;
- strengthening the institutional capacity of regulation agencies with reference to the implementation and use of renewable energies;
- improvement of information on sources of renewable energies existing in the country.

The project is financed by a US$ 30 million loan from the International Bank for Reconstruction and Development (IBRD), a US$ 10 million donation from the Global Environment Facility (GEF), and contributions from the provinces, service concession companies, service users (through tariffs) and the Ministry of Education (for schools), plus a minimum contribution from the National Treasury.

Investigations have found that more than 2 million rural inhabitants and 6 000 public services (schools, health care centres, water services, police, civil registries, etc.) lack an electricity supply. In order for these rural sites to be supplied with electricity, a combination of PV, wind, micro water turbines and/or diesel generators will be utilised.

The Electrification of the Dispersed Electric Market (MED), foreseen in the PERMER project, will supply solar home systems (SHS) for stand-alone installations, but the method of generation for community schemes will be chosen from the range of renewables available and according to the lowest cost at the time. Private companies, established in the relevant Argentine provinces, will implement the project.

The WEC Member Committee for Argentina reports that during 2003-2005 PV facilities were installed under PERMER in households, schools and first-aid stations. At the end of 2005, solar photovoltaic capacity was around 9 000 kW, including 2 000 kW on farms, according to Census data and facilities in the provinces of Buenos Aires, Jujuy, Mendoza, Neuquén, Salta and Santa Fe not included in Project PERMER.

Estimated electrical output from PV facilities in 2005 was 14 000 MWh, assuming an average of 4 daily hours of sunlight and individual consumption of about 100/150 W_p in the residential sector; 600 W_p in schools and 300 W_p in first-aid stations.

Australia

Solar PV is one of the best established renewable technologies in Australia, with over three decades of technology and market development behind it. The overall market expanded by 15.8% in 2005, bolstered by government grant programmes for rooftop applications and off-grid diesel replacement, with the grid-connected segment growing 29% and off-grid capacity by 14%. Australia's well-established non-domestic off-grid PV market in industrial, agricultural and commercial applications, such as telecommunications, signalling, water pumping, electric fences and cathodic protection, continued to be the largest sector of the PV market, accounting for 41% of capacity additions in 2005 and 55% of cumulative installations. At end-2005, installed PV power was 60 581 kW_p, of which 18 768 kW_p was off-grid domestic, 33 073 kW_p off-grid non-domestic, 6 860 kW_p grid-connected distributed and 1 880 kW_p grid-connected centralised.

The Australian Government provides support for solar energy applications through a number of programmes. Two of particular relevance to photovoltaics are summarised below.

The aim of the Photovoltaic Rebate Program (PVRP) is to encourage the installation of PV systems in residential and community buildings. A reported 1 042 systems were installed in 2005, amounting to 1.55 MW; 65% of installations, accounting for 73% of installed capacity, were on grid-connected buildings and a total of AUD 4.2 million was allocated in rebates. Since the start of the programme in 2000, over 7 600 systems, amounting to 9.5 MW_p have been installed and grants of more than AUD 34 million have been provided. PVRP is funded by the Australian Government, with administration by the State Governments.

The aims of the Remote Renewable Power Generation Program (RRPGP) are to increase the use of renewable energy for power generation in off-grid areas, to reduce diesel use, to assist the Australian renewable energy industry, to assist in meeting the infrastructure needs of indigenous communities and to reduce greenhouse gas emissions.

Each State has established a slightly different programme, to meet the specific needs of local off-grid applications. However, in general, the target groups are indigenous and other small communities, commercial operations, including pastoral properties, tourist facilities and mining operations, water pumping and isolated households that operate within diesel grids or use direct diesel generation. Core funding for this programme is provided to the States by the Australian Government, on the basis of diesel fuel excise duty collected from public generators not connected to main electricity grids. Grants are available for up to 50% of the capital cost of renewable energy systems replacing the use of diesel. The programme is administered by the State Governments, with additional funding provided by some States, and will extend to 2009/2010, although some States may expend their allocations before then.

A specific allocation of AUD 8 million has been made to the Aboriginal and Torres Strait Islander Commission (ATSIC) for the Bushlight Programme to assist with the development of industry capability and local understanding of renewable energy systems in indigenous communities.

In 2005, 2.08 MW of PV capacity was installed under RRPGP, bringing the cumulative total under the programme to 5.35 MW. Although RRPGP is not PV specific, almost all the small systems installed to date include a PV element. The overall programme has funds of some AUD 205 million allocated to it, of which AUD 141 million had been committed by the end of 2005.

Austria

The *IEA-PVPS 2005 Annual Report* states that there is no federal support for PV in Austria, as the feed-in tariff introduced in 2003 quickly reached its cap of 15 MW. However, a number of regions offer subsidies under a variety of schemes. Despite the discontinuity, growth in the PV park has been substantial in recent years, with installed capacity at year-end multiplying four-fold between 2001 and 2005.

Out of an installed total of 24 021 kW_p at end-2005, 2 895 kW_p was off-grid, 19 973 kW_p grid-connected distributed and 1 153 kW_p grid-connected centralised. Although the initial installations were standalone systems, in recent years the emphasis has been on grid-connected distributed systems, which now represent more than 80% of the overall installed capacity. Electrical output from all PV installations amounted to about 13 000 MWh in 2005.

The Austrian WEC Member Committee reports that total output from active solar heating devices was 3 712 TJ in 2005, with a somewhat larger contribution (4 248 TJ) from passive sources (e.g. use of appropriate building orientation and design). The total glazed area of solar thermal collectors in operation in 2005 was 2 319 000 m^2, giving an output capacity of about 1 623 MW_t.

With regard to new household solar collecting panels, the most recent ESTIF (European Solar Thermal Industry Federation) tabulation shows Austria in second place in terms of area installed in 2005, far ahead of sun-rich countries such as Spain or Italy.

An interesting idea combining the power of the sun and energy from biomass has been implemented in Salzburg. The *Stieglgründe* project uses a combination of solar energy and wood pellet combustion to provide heating and hot water to 128 households. The site was so constructed as to allow for maximum use of any rays from the sun. Heating costs for each household are only € 150 per annum.

Botswana

Despite Botswana's high rate of solar insolation, the country's available resource has been under-utilised in the past, being mainly used for powering telecommunication systems, water pumping, etc.

The National Photovoltaic Rural Electrification Programme, funded by the Government, ran from 1997 until 2001. From November 2001, under the PV Master Plan - a project jointly developed by the Botswanan and Japanese Governments (through the Japanese International Cooperation Agency) - several pilot schemes were instituted.

In early 2006, the Government announced that as part of its 2005-2006 Budget, the National Rural Photovoltaic Electrification Programme would offer subsidised PV packages to at least 88 villages. The package offered to villages satisfying various criteria (distance from grid, level of population etc.) includes PV panels and battery banks, solar water heating systems etc.

In April 2007 the Government called for tenders for a solar thermal power plant prefeasibility study.

Brazil

The resource potential is available in two publications: *Atlas Solarimétrico do Brasil-Banco de Dados Terrestre*, UFPE, 2000 and *Atlas de Irradiação Solar do Brasil*, LABSOLAR-UFSC & DGE-INPE, 1998. However, the methodologies used in the Atlases are different. The former is a model based on ground station information and the latter uses a model based on satellite data.

The total photovoltaic power installed in Brazil is estimated to be between 12 and 15 MW_p, 50% of the projects are for telecommunications systems and the other 50% for rural energy systems, but specific capacity data are not collected.

The Brazilian Government established PRODEEM - Programa de Desenvolvimento Energético de Estados e Municípios (Programme for Energy Development of States and Municipalities) in December 1994. The aim of the Programme is to provide energy for the basic social demands of poor communities isolated from conventional systems. PRODEEM uses photovoltaic systems to supply energy to schools, health clinics, water pumping, etc. The total PV power installed under PRODEEM stands at over 5 MW_p.

Bulgaria

The Bulgarian WEC Member Committee reports that average annual solar hours are about 2 150 and annual average solar radiation resources

1 517 kWh/m^2. The total theoretical potential of solar energy is 13 103 ttoe, and the available annual potential is about 390 ttoe.

For the 2004 edition of the present *Survey*, the Member Committee observed that Bulgaria could be divided into three zones according to the solar insolation received, namely:

Zone A - encompasses regions in the south east, part of the southern Black Sea coastal region and the valleys of the rivers Struma, Mesta and Maritza. The amount of sunshine is over 2 200 h/yr and the total solar radiation received on a horizontal surface is greater than 1 600 kWh/m^2.

Zone B - encompasses regions in the Danube plain, the Dobrudja region, the Trace lowland, west Bulgaria, the Balkan hollow fields and Stara Planina mountain regions. The amount of sunshine ranges from 2 000 to 2 200 h/yr and total solar radiation from 1 500 to 1 600 kWh/m^2.

Zone C - encompasses the remaining parts of Bulgaria, mainly the mountainous regions, where sunshine is less than 2 000 h/yr and total solar radiation less than 1 500 kWh/m^2.

Installed PV capacity at end-2005 is reported to have been negligible and no data are available regarding the installed capacity of solar water-heating devices. At present there are no grid-connected systems for utilising solar energy for electricity generation.

Canada

The Canadian solar photovoltaic (PV) industry continues to grow. Installed capacity of solar PV stands at 16.8 MW, an increase of nearly 7 MW since 2002. Most PV capacity is in off-grid applications such as transport route signalling, navigational aids, isolated residential buildings, telecommunications, and remote sensing and monitoring, generally in remote areas of the country. Solar thermal capacity in 2004 was 385 TJ.

Government programmes to encourage market development of solar technologies include various ongoing projects under the TEAM (Technology Early Action Measures) Program, as well as subsidies offered under the Renewable Energy Deployment Initiative (REDI) program for the purchase of solar water and air heating systems.

Solar hot water and solar air heating systems used directly in industrial applications, and photovoltaic equipment with capacity of 3 kW or larger qualify for tax incentives with accelerated depreciation treatment.

In 2005, a Solar Buildings Research Network of 24 top Canadian researchers in solar energy and buildings from 10 Canadian universities was created to develop the solar-optimised homes and commercial buildings of the future. The initial budget of the Network is CDN$ 6 million, and approximately 40 research projects are under way. Major Canadian energy and construction industries are involved in most of the projects. The Network is a cornerstone of Canadian efforts to promote innovative research and development in solar energy utilisation.

The province of Ontario has recently introduced the Standards Offer Program, where small renewable energy projects are able to participate in electricity markets. Under this scheme, solar PV projects will receive CDN$ 0.42/kWh.

China

It is estimated that two-thirds of the country receives solar radiation energy in excess of 4.6 kWh/m^2/day, with the western provinces particularly well endowed. China's annual solar power potential has been estimated to be 1 680 billion toe or 19 536 000 TWh. Capturing 1% of this resource, and utilising it with 15% efficiency, could supply as much electricity as the whole world presently consumes in eighteen months.

In 2004 the World Bank approved a loan and Global Environment Facility (GEF) grant to China for its Renewable Energy Development Project (REDP), in which photovoltaics feature prominently. Assistance will be provided to PV companies to market, sell and maintain 300-400 thousand systems in remote parts of the north-western provinces. The project will eventually involve the installation of around 10 MW$_p$ of PV, either on a stand-alone basis or as hybrid systems in conjunction with wind power.

China's 11th 5-Year Plan (2006-2010), approved by the Government in October 2004, stresses the need for energy conservation and diversification. In the first phase of the Village Programme, some 250 MW$_p$ of PV systems are planned for installation, bringing power to 2 million households that have been out of reach of mains electricity. Additionally, the 11th Plan will support around 50 MW$_p$ of roof-top and BIPV systems, as well as a 20 MW$_p$ demonstration plant in the Gobi desert.

In October 2005, a '100 000 solar roofs' project was approved by the Shanghai municipal government; it is planned for 70 MW$_p$ of PV capacity to be in place by 2010, with an eventual total of 360 MW$_p$, providing an annual output of 432 GWh.

In November 2006, a new law in the city of Shenzhen came into effect, promoting the use of solar energy to heat water and generate electricity. The Shenzhen Construction Bureau anticipates that half of the city's new buildings will have solar water heating and one in five will have a PV power system.

Plans have been announced to utilise PV systems on a large scale for the summer Olympic Games in 2008, exemplifying the concept of the 'Green Olympics'. It is proposed to install PV panels on the outer walls of the Olympic Stadium and gymnasia and for the majority of the street lights in the Olympic Village to be solar-powered.

Côte d'Ivoire

There is a plentiful supply of insolation in Côte d'Ivoire, with the total estimated at between 1 500 and 1 800 kWh/m^2/yr. The Government, the private sector and some non-governmental charitable organisations have been active in promoting the exploitation and use of solar energy. The applications foreseen include pumping water in villages, hospital refrigeration units in rural areas, the use of solar thermal energy to dry feeds, etc.

Denmark

There is no unified national PV programme, although a large number of projects have received support from the Renewable Energy Development Programme of the Danish Energy Authority (DEA), and through the Public Service Obligation (PSO) of the Danish transmission system operator. Since 2004, the DEA has collaborated with the electricity sector and other interested parties in pursuing a national PV strategy that encompasses RD&D, but excludes deployment.

As part of the plan to increase the deployment of building-integrated systems, a 4-year nationwide solar cell project, SOL 1000, is being implemented. The programme is intended to demonstrate low-cost and architecturally acceptable integration of PV technology on the existing housing stock. The objective is to install about 650 kW$_p$ of BIPV. Alongside this project is running an R&D package (SOL 2000A) funded by the PSO.

At the end of 2005 installed PV power was 2 650 kW$_p$, of which 70 kW$_p$ was off-grid domestic, 225 kW$_p$ off-grid non-domestic and 2 355 kW$_p$ grid-connected distributed. Output of electricity from PV amounted to 2 160 MWh in 2005.

The Danish WEC Member Committee reports that heat output from active solar systems in 2005 was 49 terajoules. The total glazed area of solar thermal collectors in operation in 2005 was 337 000 m^2, giving an output capacity of about 236 MW$_t$.

Egypt (Arab Republic)

Egypt is located in the world's solar belt and has an excellent solar availability. The Egyptian WEC Member Committee reports that average solar radiation ranges from about 1 950 kWh/m^2/yr on the Mediterranean coast to more than 2 600 kWh/m^2/yr in Upper Egypt, while about 90% of the Egyptian territory has an average global radiation greater than 2 200 kWh/m^2/yr.

Recognising the important role renewable energy can play in meeting future energy needs, the New & Renewable Energy Authority (NREA) has set itself the target of providing at least 3% of the country’s electrical energy demand from renewables by the year 2010.

Photovoltaic (PV) solar systems are presently considered economically advantageous only in remote applications of low power demand, where a grid extension appears non-economic, while conventional stand-alone power sources (e.g. diesel generator sets) show excessive operating costs, in addition to polluting the environment.

A number of PV systems totalling about 4.5 MW_p have been installed in Egypt, primarily by NREA, but also by other national and international entities, including some private companies.

The main applications are water pumping, desalination, rural clinics, telecommunications, rural village electrification, ice-making, billboards and cathodic protection.

The Egyptian Member Committee has also reported that a protocol has been confirmed between the NREA and the Italian Ministry of Environment and Territory (IMET) in the framework of the Renewable Energy for the Mediterranean Countries Program MEDREP, to use PV systems for lighting applications in two villages located in the Siwa Oasis (Matrouh Governorate), consisting of 100 households, 2 medical centres, 1 school, 3 mosques and 80 street lamps. The implementation of these projects is greatly dependent on the availability of funds (mainly international support), owing to the relatively high investment costs.

Ethiopia

Solar energy availability in Ethiopia ranges between 1 700 and 2 200 $kWh/m^2/yr$. Solar PV is used for telecommunication applications, for rural lighting and for rural social services (water pumping, health and education). Three-quarters of the installed PV capacity is used for telecoms. Total installed PV capacity was 2 940 kW_p at end-2005.

Solar water heating is employed by some urban homes and commercial establishments. At the end of 2005 an estimated 200 units, with 400 m^2 of absorber area, were operational.

Finland

The average annual insolation in Finland is 1 150 kWh/m^2. The seasonal variation of solar radiation in Finland is large; the main part of solar radiation is obtained between March and September.

The sum of installed photovoltaics is 4.0 MW_p, of which 95% consists of local PV systems in summer houses, etc., mostly small units in the range of 50-100 W_p. Recently, two somewhat larger installations have been made in Viitasaari (5 kW_p) and Saarijärvi (6 kW_p).

Whilst the PV sector remains fairly modest, the Ministry of Trade and Industry's Action Plan contains a national target of 40 MW_p installed PV capacity by 2010, with a corresponding 2025 level of 500 MW_p.

The total glazed area of solar thermal collectors in operation in 2005 was 14 000 m^2, giving an output capacity of about 10 MW_t.

France

By end-2005 France (including its overseas departments [DOM]) had a total installed PV capacity of 33 043 kW_p, of which 13 844 kW_p was off-grid domestic, 6 232 kW_p off-grid non-domestic and 12 967 kW_p grid-connected distributed. Metropolitan France accounted for almost 49% of total PV capacity and about 42% of PV output. The annual average increase in capacity between 2000 and 2005 was about 24%.

The principal sources of subsidies for PV installations in France are ADEME (Agence de l'environnement et de la maîtrise de l'énergie: the body charged with promoting renewable energy), the regional councils and the European Commission.

An Arrêté dated 7 July 2006 specifies the following new targets for PV installations: an additional 160 MW by 2010 and an additional 500 MW (including the 160) by 2015.

The French feed-in tariff for PV electricity was updated by an Arrêté dated 10 July 2006 (€ 0.30 to 0.55/kWh), for installations with a capacity of below 12 MW.

Solar thermal output in 2005 is reported to have been 1 632 TJ, of which 941 was in metropolitan France. The total glazed area of solar thermal collectors in operation in 2005 was 396 000 m^2, giving an output capacity of about 277 MW_t.

The Loi POPE of 13 July 2005 specifies a target of 200 000 solar water-heaters and 50 000 solar roofs per annum in 2010.

All solar equipment benefits from an increase in the tax credit to 50% from 1 January 2006.

Gabon

The Gabonese WEC Member Committee reports that Gabon's average daily insolation is about 4 kWh/m^2 and that there are approximately 300 days of sunshine per year. Photovoltaic cells are used in the electrification of villages and in telecommunications.

Germany

Germany has the highest level of installed PV capacity amongst the European members of the IEA-PVPS. At end-2005 its capacity stood at 1 429 MW_p, 25 times that of the next biggest country (Spain). Out of the installed PV total, 29 MW_p was off-grid and 1 400 MW_p grid-connected.

Recent growth has been nothing short of phenomenal: averaging 58% per annum from 1999 to 2003 and then accelerating to 80% or more in 2004 and 2005. Major factors contributing to this rapid rate of expansion were the highly successful 100 000 Rooftops Solar Electricity Programme which ran from 1999 to 2003 and the Renewable Energy Sources Act (EEG) which, from April 2000, guaranteed a feed-in tariff for PV.

The Second Amendment of the Renewable Energy Sources Act (EEG) came into force on 1 January 2004. It is expected to promote even further growth in the German solar industry in the coming years. The basic tariff available for solar power installations built in 2005 is € 0.513/kWh. There are bonuses for small installations and BIPV.

Solar thermal technology is also expected to benefit from a market incentive programme. The total glazed area of solar thermal collectors in operation in 2005 was 6 554 000 m^2, giving an output capacity of about 4 588 MW$_t$.

Plans were announced in March 2007 for the construction of one of the world's largest PV power plants. The facility will comprise some 400 000 m^2 of solar panels, with a generating capacity of 40 MW$_p$, and will be erected on a former military airfield near Leipzig.

Greece

Despite the existence of a very high potential for solar energy applications and the beginning of their deployment in the mid-1970s, major applications have so far been restricted to SWH collectors. There has been a negligible market for large-scale hot water systems in the commercial sector (hotels, hospitals and swimming pools) and an even smaller penetration in industry.

In order to promote solar energy the Hellenic State provides a very favourable taxation environment for solar applications but individual consumers' purchases are mainly limited to SWH collectors, because of the high cost of photovoltaic applications. The total glazed area of solar thermal collectors in operation in 2005 was 3 047 000 m^2, giving an output capacity of about 2 133 MW$_t$.

Guinea

The WEC Member Committee for Guinea reports that the republic is well-endowed with solar energy. The average annual hours of sunshine range from 2 000 at Conakry to 2 700 at Kankan, whilst the average daily insolation is estimated at 4.8 kWh/m^2, equivalent to some 1 750 kWh/m^2/yr. Installed capacity of PV systems is reported to have been 148 kW$_p$ at end-2005.

Hong Kong, China

The resource potential estimated by a government study in 2002 suggested that with massive deployment on buildings, solar photovoltaic power could generate up to several thousand GWh per year.

In Hong Kong, government, utilities, schools and commercial buildings combined, have more than 800 kW capacity of grid-connected solar photovoltaic panels, mostly on buildings. The largest installation is 350 kW on the roof of the new headquarters of the Electrical and Mechanical Services Department. There are also a number of installations using solar thermal energy for water heating.

Solar energy is the subject of research at a number of universities in Hong Kong. Studies include new photovoltaic materials and systems; integration of photovoltaic systems with buildings; assessment of system performance in the Hong Kong environment; utilisation of light and heat as an aspect of building architecture and design; solar-boosted heat pump demonstration and assessment.

Hungary

The Hungarian solar energy market is in an early stage of development, compared with wind or biomass energy applications. Installed PV capacity was about 100 kW_p at end-2005, with output during the year totalling some 150 MWh.

Three-quarters of installed PV systems are autonomous: microwave telecommunication stations, highway emergency phones, traffic data acquisition stations, meteorological survey stations, safety systems, electric fences, water supply systems, monitoring systems in the gas industry, lighting, remote area houses, etc.

About a quarter is grid-connected. These are mainly subsidised pilot or demonstration applications: e.g. at a gasoline filling station, university projects, etc.

There are less than 1 000 applications of solar heat, consisting mainly of small-scale house heating and hot water production. The total glazed area of solar thermal collectors in operation in 2005 was 5 000 m^2, giving an output capacity of about 4 MW_t.

India

The Ministry of New and Renewable Energy (MNRE), formerly the Ministry of Non-Conventional Energy Sources, working in conjunction with the Indian Renewable Energy Development Agency (IREDA) continues to promote the utilisation of all forms of solar power, as part of the drive to increase the share of renewable energy in the Indian market. This promotion is being achieved through R&D, demonstration projects, government subsidy programmes, programmes based on cost recovery supported by IREDA, and also private sector projects.

India has a good level of solar radiation, receiving the solar energy equivalent of more than 5 000 trillion kWh/yr. Depending on the location, the daily incidence ranges from 4 to 7 kWh/m^2, with the hours of sunshine ranging from 2 300 to 3 200 per year. Solar thermal and solar photovoltaic technologies are both encompassed by the Solar Energy Programme that is being implemented by the Ministry. The Programme, regarded as one of the largest in the world, plans to utilise India's estimated solar power potential of 20 MW/km^2, and 35 MW/km^2 solar thermal. The country has also developed a substantial manufacturing capability, becoming a lead producer in the developing world.

Within the overall drive towards renewable energy, the Ministry conducts separate programmes for solar thermal and solar photovoltaic.

- The *Solar Thermal Development Programme* covers solar water heating, solar cooking, solar air heating and solar buildings.

India's overall potential for ***solar water heating systems*** has been estimated to be 140 million

m^2 of collector area. Up to the present, about 1 million m^2 of collector area has been installed – a low level in comparison with the potential, and as compared with other countries, notably China. A Government scheme for 'Accelerated development and deployment of Solar Water Heating systems in domestic, industrial and commercial sectors' has been introduced, with the object of promoting the installation of another million m^2 of collector area during FY 2005-06 and 2006-07. The scheme offers a number of financial and promotional incentives, along with other measures of support. The installation of Evacuated Tube Collectors is being officially encouraged.

Five types of ***solar cookers*** have been developed:

- *cardboard solar cooker*: low-cost, portable, one or two dishes at a time;
- *box solar cooker*: small, four dishes at a time, intended for small families;
- *dish solar cooker*: fast cooking device for homes and small establishments, for 10-15 people;
- *community solar cooker for indoor cooking*: large, automatically-tracked parabolic reflector, standing outside kitchen through an opening in the north wall, with a secondary reflector further concentrating the rays on to the bottom of the black-painted cooking pot, for 40-50 people;
- *solar steam cooking system*: large, automatically-tracked parabolic reflectors, coupled in a series and parallel combination, generating steam for use in community kitchens, for thousands of people, usually installed in conjunction with a conventionally fuelled boiler; the world's largest solar cooking system installed at Tirumala in Andhra Pradesh, has the capacity to provide food for 15 000 people per day.

Solar air heating technology has been applied to various industrial and agricultural processes (e.g. drying/curing, regeneration of dehumidifying agents, timber seasoning, leather tanning) and also for space heating; many types of solar dryers have been developed for use in different situations. The Government provides financial support for solar air heating/drying systems, and also for solar concentrating systems such as the 160 m^2 parabolic-dish concentrator recently installed for use in milk pasteurisation at a dairy in Maharashtra.

Solar buildings have been promoted by the MNRE in an effort to increase energy efficiency; the state government in Himachal Pradesh has actively promoted the incorporation of passive solar design into building design.

- The *Solar Photovoltaic Programme (SPV)* promoted by the Ministry for the past two decades, has been aimed particularly at rural and remote areas. Following the success of the country-wide SPV demonstration and utilisation programme during the period of the Ninth Plan, it is planned, with certain modifications, to continue it during the Tenth Plan (2002-2007).

Of the approximately 80 000 villages not currently connected to the grid, about 18 000 are too remote ever to be considered. The Ministry has the objective that by 2010 they will all have access to power from renewable energy sources, with the Tenth Plan electrifying 5 000 of them. During 2005-2006 the Ministry supported the supply of solar lanterns to certain unelectrified villages.

Among the numerous stand-alone applications of PV found in India are the following:

- emergency/back-up lighting for roads and other areas;
- control systems for switching street lights on/off;
- back-up systems for traffic signals;
- illuminated road studs;
- warning lights at road hazards;
- BIPV systems for load-shaving at peak hours;
- power packs to replace small gasoline/kerosine-powered generators.

In a country where agriculture is a major component of the economy, the SPV Water Pumping Programme will continue to subsidise the large-scale use of PV-powered (1 800 W_p) pumping systems for farmers.

The Ministry is also implementing a programme for water-pumping windmills, small aerogenerators and wind-PV hybrid systems to enable the huge Indian wind resource to be harnessed in conjunction with the solar power available. These applications will be fully researched and demonstrated prior to deployment in remote areas.

The MNRE is developing a chain of Akshay Urja Shops (previously called Aditya Solar Shops). These are showroom-cum-sales and service centres, initially established to sell solar energy products; their scope has now been widened to cover all renewable energy systems and devices. So far, 104 shops have been opened in 28 States or Union Territories, and the Ministry plans for at least one to exist in each district throughout the country.

Indonesia

The archipelago of Indonesia comprises over 17 000 islands (according to the latest count using satellite mapping) of which approximately 6 000 are inhabited. Difficulties in extending the national grid across the islands to the widely dispersed population meant that in 1995 only about 58% of the country's 62 000 villages were electrified. Historically, areas that could not be supplied with conventional electricity from the national grid have relied upon hydro-electricity and stand-alone diesel generators to power mini-grids, or used kerosine for lighting.

Indonesia's situation close to the equator and its daily average insolation level – estimated at 5 kWh/m^2 - make it highly suitable for the installation of solar energy devices, especially for the huge rural population and in remote areas.

Both solar thermal and solar PV applications have been installed throughout the country, estimated in 2004 to total about 5 MW. Most of the solar thermal installations are used for domestic water heating, agriculture or crop drying and cooking. Solar PV systems are used at community centres for lighting, pumping and at health centres for the refrigeration of medicines.

Under the National Plan for PV, the indigenous manufacture of photovoltaic modules will be developed, the utilisation of PV systems in both rural and urban areas will be increased and the mechanism for grid-connected PV will be established.

Although the use of renewable energy is, at present, fairly limited, the Government plans to increase its share. The National Energy Policy states that by 2025 renewable energy will provide 17% of the energy mix (of which biomass, nuclear, hydro, solar, wind and coal bed methane will supply 5%).

Iran (Islamic Republic)

According to the Iranian WEC Member Committee, the average annual solar energy potential is about 6 570 MJ/m^2 or 1 825 kWh/m^2. Most areas in Iran record more than 300 days of sunshine, or over 2 800 hours, in a year.

Installed PV capacity at end-2005 is reported as 300 kW, with 2005 output amounting to 230 MWh. The capacity of solar heating systems is estimated to have been around 5 000 kW at the end of 2005.

Programmes for promoting the utilisation of solar energy fall into three categories:

- building up capacity, such as running university-level training courses, supporting and establishing research centres, encouraging manufacturers to produce the required equipment and systems;
- carrying out pilot projects by the Government, with the aim of clearing the ground for the private sector to come forward;
- conducting potential assessment studies.

Solar projects include:

- a 17 MW solar thermal power plant, which would be installed by 2009;
- 50 MW (or more than 1 million m^2) of solar water heaters by 2009;
- installation of several different types of PV systems;
- a pilot plant for a parabolic-trough solar thermal power plant, with a capacity of 250 kW;
- installation of PV systems in 40 isolated village households.

Israel

With an average annual insolation of approximately 2 000 kWh/m^2 and few natural energy resources, Israel has pioneered the use of solar energy. However, whilst the 1980 law requiring the installation of solar water heaters has had a dramatic effect, PV activity remains largely in the realm of academic research.

The 1980 Solar Law is an amalgam of different legislative measures, all designed to lay down national standards and regulations. The Planning and Building Law requires the installation of solar water heaters for all new buildings (including residential buildings, hotels and institutions, but not industrial buildings, workshops, hospitals or high-rise buildings in excess of 27 m), dictating the size of the installation required for a particular type of building; the Land Law governs solar installations in existing multi-apartment buildings and the Supervision of Commodities and Services Law provides governmental supervision of the quality of installations and their guarantees.

Almost all Israel's residential buildings have solar thermal systems, the vast majority of which are utilised for water heating. It has been reported that the use of solar collectors saves the country in the region of 600 000 toe/yr.

Although the Israel Electric Corporation is required to purchase electricity from private producers, there are no incentives for PV systems. The extensive national grid precludes the same penetration by PV as has been enjoyed by solar water systems. There is no PV module manufacturing capability within the country and currently most activity is concentrated on maintaining the technical excellence that has been achieved through academic research. However, during 2002 PV-operated cameras for vehicle number-plate recognition were installed for use on Israel's first toll road. Additionally, there are instances of PV being used for lighting, irrigation, pumping and refrigeration and in parking-ticket machines. A demonstration PV project was initiated in 2005 in the Bedouin village of Drijat, in the Negev desert. In its first phase, the project provided stand-alone PV systems to 20 households, 6 street lamps, a school and a mosque.

At end-2005 there was 1 044 kW_p of installed PV power, of which 809 kW_p was off-grid domestic, 210 kW_p off-grid non-domestic, 11 kW_p grid-connected distributed and 14 kW_p grid-connected centralised.

In November 2002 the Government passed a resolution stating that by 2007 at least 2% of total electric energy must be generated from renewable energy, rising to 5% by 2016.

Italy

Since the early 1980s, the main thrust of solar energy in Italy has been photovoltaic, the development of which has ranged from research on materials and devices and experimentation for grid and non-grid applications to the dissemination of such technology through various incentive programmes.

Currently, PV electricity is supported via dedicated premium feed-in tariffs with a fixed premium in the range of € 44.5-49.0/MWh according to the plant size for the green value, and via a tariff linked to the market price for the power. Plants up to 20 kW can choose to have the power paid via net-metering or via tariff.

Current applications include small islands electrification, telecom systems, environmental data collection and transmission, isolated spot lighting at bus stops, etc..

According to the IEA-PVPS, 14% of end-2005 PV capacity was off-grid domestic, 19% off-grid non-domestic, 49% grid-connected distributed and 18% grid-connected centralised.

The total glazed area of solar thermal collectors in operation in 2005 was 516 000 m^2, giving an output capacity of about 361 MW_t.

In November 2003 ENEL (the largest Italian utility) and ENEA (the Italian Agency for New Technology, Energy and Environment) announced their collaboration on the 'Archimede' project. ENEL's existing Priolo Gargallo gas combined-cycle power plant located in Sicily will be expanded with the addition of a solar plant to be constructed alongside. The innovative technology, albeit inspired by the 3rd century BC mathematician, will use parabolic mirrors to concentrate and accumulate the power from the sun during daylight hours. With the use of a new fluid based on low-cost fused salts and capable of allowing high temperatures to be reached, the process will use the thermal energy collected to produce vapour and thus electricity during a 24-hour cycle. It is estimated that there will be a saving of some 12 000 toe per annum and a reduction in the region of 36 000 t/yr of CO_2 emissions. The testing period has proved to be successful and at the end of March 2007 it was announced that an accord had been signed between ENEL and ENEA for installation to begin. It is expected that the plant will be operational in 2009.

Japan

As one of the 19 member countries of the Implementing Agreement on Photovoltaic Power Systems (IEA-PVPS) Japan had the highest installed PV capacity (636.8 MW_p) at end-2002, when it was more than double that of the next highest country, Germany. In three years, however, Germany managed to overtake Japan, and by end-2005 was 7MW_p higher than Japan.

Of Japan's 1 421.9 MW_p total capacity, 1.1 MW_p was for the off-grid domestic market, 85.9 MW_p for off-grid non-domestic, 1 332.0 MW_p for grid-connected distributed and 2.9 MW_p for grid-connected centralised.

The 1997 New Energy Law led to The Total Primary Energy Supply Outlook in 1998 which specified that the target for installed PV was to be 5 000 MW by FY2010. In 2001 this target was reduced to 4 820 MW. The Ministry of Economy, Trade and Industry (METI) is charged with promoting the measures necessary to achieve this target. The 'Renewable Portfolio Standard' Law introduced during 2002 requires energy suppliers to use a certain percentage of renewable energy.

In addition to the main demonstration programmes ('PV Field Test for Industrial Use' and 'Demonstrative Development of Centralised Grid-Connected PV Systems') both started in FY2002, METI also began in FY2002, three implementation programmes ('Residential PV System Dissemination Programme', 'Introduction and Promotion of New Energy at the Regional Level' and 'Financial Support for Entrepreneurs Introducing New Energy').

The Residential PV System Dissemination Programme granted subsidies to private purchasers of PV installations, providing that they recorded and reported the operational data of their system. At the end of FY2004, the cumulative capacity of the 217 000 residential PV systems installed under this programme amounted to 795 MW_p. Nearly 40 000 applications were accepted in 2005, for a total capacity of 155.7 MW_p. By October 2005 the budget for FY2005 had become exhausted, resulting in the scheme's termination.

It was anticipated in 2006 that some 70 000 residential PV systems would be installed during the year and that the total of incremental PV capacity in all applications could reach around 350 MW_p. In Japan, most PV installations are on residential property. About 80% of residential systems have been installed on existing houses and 20% on new properties. One commentator has remarked on the fact that, although fully roof-integrated PV systems are readily available, the number of such installations is quite small, and suggests that purchasers prefer to display their green credentials by opting for panels rather than the less noticeable tiles.

The majority of PV installations are likely to continue to take place in the residential sector, at a rate of between 100 000 and 200 000 (400-800 MW_p) per annum. The number of larger installations on public buildings and industrial property is expected to increase, whilst further applications may be developed in transport and agriculture.

Off-grid non-domestic PV systems are being deployed for use in telecommunications, traffic signs, telemetering, ventilation and lighting.

The production and deployment of solar hot water systems began more than 50 years ago and the market developed during the ensuing three decades. The oil crises of the 1970s fostered further growth but in the late 1990s stagnation set in, not least because of the Government's termination of low-interest loans. In a survey published in April 2003, ESTIF (European Solar Thermal Industry Federation) estimated that 7.360 million m^2 of glazed collectors were in operation in Japan at the end of 2001, of which 7.219 million m^2 were flat-plate collectors and 0.141 million m^2 were vacuum collectors.

Jordan

Jordan lies in the so-called earth-sun belt area and has a high solar potential, with annual average insolation in the region of 1 800 kWh/m^2/yr.

The Jordanian WEC Member Committee reports that a number of studies and surveys on the utilisation of solar energy have been made for various locations, through the so-called Phoebus Project. Their outcome was encouraging and indicated that the utilisation of solar energy for remote applications is feasible.

The use of solar energy for thermal applications, including electricity generation, is technically possible, owing to the high solar energy intensity (which exceeds 2 000 kWh/m^2/yr at some locations) and other favourable factors. From an economic point of view, however, solar power plants are not yet viable and would need additional support to be competitive with conventionally generated power.

Currently the main use of solar energy is for domestic water heating, with approximately 30% of houses having such installations; to supply this market, more than 25 manufacturers are producing locally-designed solar water heater systems.

In addition, photovoltaic systems are used in remote areas throughout the country. PV installations cover a variety of applications, such as water pumping, telecommunications, schools and others, with a reported total capacity of 184 kW_p.

Kenya

Kenya receives a plentiful supply of solar radiation, averaging between 4 and 6 kWh/m^2/day, but only a small proportion of this resource has so far been harnessed.

On its official website, the Ministry of Energy states that an estimated 220 000 PV units are in current use, for lighting, water pumping, refrigeration and telecommunications. The Government is presently carrying out a programme of installing PV systems in schools and other institutional buildings in a number of remote areas, as part of its drive to increase the proportion of renewable sources within Kenya’s overall energy supply.

Solar thermal devices are used for heating and drying, with around 7 000 units in operation at present.

Korea (Republic)

The years 2004 and 2005 witnessed rapid growth in Korea's use of photovoltaics, reflecting the implementation of The 2nd Basic Plan for New & Renewable Energy Technology Development & Dissemination, established in 2003. This Plan sets a target of a 3% share of total energy consumption for new and renewable energy in 2006, rising to 5% by 2012. The Ministry of Commerce, Industry and Energy (MOCIE) has selected PV as one of the three key technologies to be developed and promoted. It is planned to bring Korea's PV capacity up to 1 300 MW_p by 2012, through installations on 100 000 residential roof-tops and 70 000 commercial and industrial buildings.

In two years installed PV capacity rose by 150%, to reach 15 021 kW_p by the end of 2005. Under the direction of MOCIE, an intensive programme of research, development and demonstration is being undertaken, with the object of improving the technological and commercial aspects of photovoltaic products and promoting their diffusion, both in Korea and abroad.

A project was announced in May 2007 for a 19.6 MW_p PV power plant, to be built in Sinan, 400 km south-west of Seoul. The scheme, consisting of more than 100 000 sun-tracking solar modules, is expected to generate up to 27 GWh. On completion, scheduled for late 2008, it will become one of the world's largest PV power stations.

Latvia

Latvia's total solar radiation varies between 900 and 1 100 kWh/m^2/yr; although the amount of sunshine the country receives is only about 1 200 h/yr, solar power is being utilised to good effect.

PV systems have been installed in lighthouses and lightships and in some small demonstration projects, as at Riga Technical College.

Solar collectors have been installed at a number of schools and other locations. The Danish-financed solar thermal project at Aizkraukle Secondary School Nr. 2, completed in 2002 with 155 m^2 of collectors, was at the time the largest such project in the Baltic States. The total glazed area of solar thermal collectors in operation in 2005 was 2 650 m^2, giving an output capacity of about 2 MW_t.

Lithuania

The total annual potential of solar energy in Lithuania is assessed at 1 000 kWh/m^2 and the technical potential at about 1.5 TWh per annum. So far, solar energy has been used for heating, hot water production and the drying of agricultural products.

The project, Development of the Lithuanian solar program 2000-2005 and its implementation into the World Solar Program, coordinated by the Institute of Lithuanian Scientific Society and funded by UNESCO, envisaged the construction of 0.05 MW of photovoltaic power equipment and 1 000 m^2 of solar collectors.

The Lithuanian WEC Member Committee reports that the total area of solar collectors installed is currently about 1 000 m^2, with total heat production in 2005 some 500 MWh.

Mexico

The Mexican WEC Member Committee reports that by end-2005 a cumulative total of 18 650 kW PV capacity had been installed, and that total generation from PV systems in 2005 was just over 34 000 MWh. It also reports that recent studies for a forthcoming 4-year rural electrification programme, co-financed by the GEF, the World Bank and the Mexican Government, have shown that PV would be the least expensive alternative in more than 51% of almost 9 500 targeted communities in four southern states. A pilot neighbourhood of 100 houses with PV roof-tops of 1 kW each is planned for implementation in northwest Mexico in the near future.

In 2005, the Mexican PV market was about 0.5 MW_p, of which rural electrification accounted for 307 kW_p (including 242 water pumping systems with 200 kW_p), grid-connected systems for 30 kW_p, and professional applications (telecommunications, offshore oil platforms, etc.) for 175 $kW_{p.}$

The *Balance nacional de energía 2004* states that at end-2004 there were 642 644 m^2 of flat-plate solar collectors installed, mainly used for heating water for swimming pools and general hygiene. Solar heat production in 2005 was an estimated 3 075 TJ.

Namibia

Namibia has a substantial solar energy potential, owing to its high level of solar radiation. Currently efforts are being made by the Government and its partners to increase the use of solar energy. People can buy their equipment through the government-sponsored soft-interest loan scheme, the Solar Revolving Fund and Bank Windhoek.

Current and planned projects include:

- the removal of barriers to the Namibian renewable energy programme (UNDP/GEF/Ministry of Mines and Energy);
- establishment of a renewable energy and energy efficiency institute;
- building capacity for renewable energy and energy efficiency.

Solar home systems, solar water heaters and PV water pumps are the most widely-used applications of solar energy, but there are also a number of telecommunication systems.

The Namibian WEC Member Committee reports that at end-2005 some 700 kW of PV capacity had been installed, providing an output of 306.6 MWh during the year.

Netherlands

There is at present no national programme for organising the deployment of photovoltaic systems, but various aids to individuals and companies are in place. The feed-in tariff has, however, been set at a low level and requires the PV owner to buy a special meter, to become a member of EnerQ, the managers of the MEP (Milieukwaliteit van de Elektriciteitsproductie) regulation under which the tariff is offered, and to acquire green-certificates. A net-metering scheme for small-scale domestic PV systems was launched in 2005.

At end-2005 a total of 50 776 kW_p PV had been installed, of which 4 919 kW_p was off-grid, 43 377 kW_p grid-connected distributed and 2 480 kW_p grid-connected centralised.

By the end of 2005, the City of the Sun Project, partly financed by the European Union, had installed 3.7 MW_p (out of a targeted level of 5 MW_p) in the new HAL neighbourhoods in the vicinity of Heerhugowaard, Alkmaar and Langedijk.

Development of the Dutch solar thermal market began in the mid-1970s and, owing to support from the Government in the form of a Long-Term Agreement for the Implementation of Solar Hot Water Systems (SHWS) and also subsidy schemes, it showed considerable success, especially in the house-building sector. By 2001 nearly 15% of all new residential dwellings were supplied with a Domestic Hot Water (DHW) system.

Installation of solar thermal systems in existing buildings had almost stopped after 2003 when the financial incentives ended but the new-build market was revitalised owing to tighter energy efficiency regulations. In 2005, 15-20% of all new buildings incorporated a solar thermal system and the total glazed area of solar thermal collectors in operation was 304 000 m^2, giving an output capacity of about 213 MW_t.

Norway

The majority of Norway's commercial solar market consists of off-grid PV systems. By the end of 2002 a total of about 100 000 private systems had been installed, mostly in recreational cabins and leisure craft, and the market was showing signs of approaching saturation. In the public sector, the Norwegian Coastal Administration had installed approximately 1 840 installations with a total of about 3 600 modules, supplying lighthouses and coastal lanterns along Norway's coastline.

There are no public schemes to promote PV applications, and no national demonstration or field-test programmes were in operation in 2005. Nevertheless, several buildings with integrated PV have been constructed in recent years, the most notable being the new Oslo Opera House.

Total installed PV capacity was 7 252 kW_p at end-2005, of which the off-grid domestic market accounted for 6 800 kW_p (94%), off-grid non-domestic 377 kW_p and grid-connected distributed 75 kW_p.

Pakistan

The *Pakistan Energy Yearbook 2006*, published by the Hydrocarbon Development Institute of Pakistan, reports that in 2005-2006 the Alternative Energy Development Board (AEDB) successfully deployed solar energy technologies in nine villages under its '100 Solar Homes Programme'. In each of the villages a hundred or more houses were provided with a basic electrical installation, comprising an 88 W solar panel, four LED lights, a 12 V DC fan and a TV socket. Each of the 991 households in the scheme was also provided with a solar cooker and a solar disinfecting unit.

In another initiative, the AEDB has devised a Solar Water and Desalination project to provide clean potable water in the remote areas of Tharparkar in Sindh. Five villages in Tharparkar will each be provided with a PV brackish-water pump, and a solar thermal desalination unit will be installed in each house.

The Board has also developed a project for the demonstration of solar thermal power generation technologies, including Parabolic Trough (35 kW) and Stirling Dish (10 kW). With the assistance of the provincial governments of Sindh and Balochistan, demonstration sites have been identified.

Private-sector companies in Pakistan, with the facilitation of the AEDB, have developed a number of products for areas that have been electrified with solar energy, including LED lights, solar lanterns, pedal generators, hand generators and solar mobile-phone chargers.

Paraguay

The Paraguayan WEC Member Committee reports that work on the utilisation of solar energy in rural communities is being carried out in conjunction with the Latin American Energy Organization (OLADE). Other projects in this area are under way, with the support of other international organisations.

Peru

The Peruvian WEC Member Committee reports that the installed capacity of photovoltaic cells at the end of 2005 was 3 713.5 kW_p and that electricity generation from PV totalled 3 109.9 MWh in 2005. Direct output of heat from solar devices amounted to 62.6 TJ.

Solar Photovoltaic Panels are mainly used for village electrification, water pumping and telecommunication systems. The Ministry of Energy and Mines and some NGOs provide these types of system.

In the period 1996-2002 the Ministry of Energy and Mines installed 1 523 PV panels of 50 W_p each. According to the National Rural Electrification Plan, in the period 2005-2014, the installation of 4 524 PV panels is planned.

Solar thermal systems are used mainly for water heating, solar drying and cooking.

Portugal

Utilisation of Portugal's solar energy resource has, up to the present, been relatively low. The Government has now set goals for the development of renewable energy, including a target of 150 MW_p for installed capacity of PV by 2010. Penetration of the market will be facilitated by a favourable feed-in tariff, as well as financial and fiscal incentives. At end-2005, the installed PV capacity was only about 3 000 kW_p (of which 73 kW_p was grid-connected).

Portugal's first building-integrated PV system (12 kW_p) was developed by the National Institute for Engineering and Industry Technology (INETI), and installed on the south façade of the Renewable Energy Department's Solar Building XXI. Another PV project completed in 2005 was a 25 kW_p system installed by the German Energy Agency (DENA) at the Lisbon German School.

Located in Alentejo, 200 km southeast of Lisbon, the 11 MW, 52 000 PV module, Serpa power plant was inaugurated at the end of March 2007. The world's largest centralised PV power plant, with an eventual capacity of 62 MW_p, is planned for construction in the same area. At end-October 2006, the first phase of the project (42 MW_p: 32 MW_p fixed panels + 10 MW_p solar trackers) was stated to have a scheduled completion date of September 2008, with the second phase (20 MW_p) planned for construction during 2008-2010. Together the two plants account for 49% of the Government's maximum quota for PV power in 2010.

The total glazed area of solar thermal collectors in operation in 2005 was 161 000 m^2, giving an output capacity of about 113 MW_t.

Romania

The Romanian WEC Member Committee reports that the solar energy potential, as given by the average amount of energy from solar radiation on a horizontal surface, is about 1 300 $kWh/m^2/yr$.

The geographical distribution of the solar energy potential indicates that more than half of Romania's area benefits from an annual energy flow of between 1 000 and 1 300 $kWh/m^2/yr$. The solar-thermal potential is 144 000 TJ/yr, whilst the solar-electric potential is 6 TWh/yr.

The planned project and research programmes will promote investment projects in order to ensure optimum conditions for the development of medium and long-term applications.

The demonstration projects for heat generation based on solar sources are developed by means of high-performance solar-thermal systems (e.g. as a heat carrier and for hot-water production in individual households), which can operate in parallel with conventional heating systems.

For the development of demonstration programmes, especially for rural electrification, relatively low power (ranging from 200 W to 5 000 W) solar applications will be developed.

On the basis of feasibility studies, projects designed for PV grid-connected systems will be put into operation.

Current applications comprise:

- demonstration grid-connected PV systems;
- building-integrated grid-connected systems;
- rural electrification;
- small off-grid public & private installations;
- hybrid PV/wind systems;
- PV for telecommunications.

Russian Federation

With its vast size, Russia necessarily receives a very substantial amount of solar radiation, but the geographical diversity of the country means that the resource is not uniformly available. The average solar radiation in the southern regions is about 1 400 kWh/m^2/yr whilst the remote northern areas receive about 810 kWh/m^2/yr.

The regions with the best potential comprise the North Caucasus, regions bordering the Black Sea and the Caspian, and the southern parts of Siberia and the Far East. Areas below or near latitude 50^{o}N have particularly favourable solar radiation. The resource is extremely seasonal: at 55^{o}N it ranges from 1.69 kWh/m^2/day in January to 11.41 kWh/m^2/day in July.

Although it has been estimated that the gross potential, the technical potential and the economic potential for solar energy are 2.3 trillion tce, 2 300 million tce and 12.5 million tce, respectively, Russia's enormous indigenous fossil fuel reserves have meant that historically, little attention has been paid to the renewable energies. However, with about 10 million people having no access to an electricity grid and most rural settlements having no centralised heat supply, the possibilities for off-grid solar energy or hybrid applications are huge.

The building of a single Solar Power Plant 'Kislovodskaya SPP' (1.5 MW), with assumed output 2.04 million kWh, has been delayed.

Spain

The Instituto para la Diversificación y Ahorro de la Energía (IDAE), an organisation within the Ministerio de Industria, Turismo y Comercio, produced a Plan for the Promotion of Renewable Energy in Spain covering the period 2000-2010, which was approved by the Spanish Government on 30 December 1999. In 2005, IDAE produced a revision, in the shape of the Plan de Energías Renovables en España (PER) 2005-2010. This plan retains a commitment for renewables to cover at least 12% of total energy consumption in 2010, and for renewables to provide 29.4% of electricity demand in the same year. However, some of the specific objectives for individual sources have been modified. The current targets for the development of solar energy applications are summarised below.

- **low-temperature solar-thermal energy**: the potential area of solar panels is estimated at 26.5 million m^2; the objective for installations during 2005-2010 is 4.2 million m^2. With the inclusion of the 0.7 million m^2 in place in 2004, a total of nearly 5 million m^2 of solar panels could be operational by the end of 2010. The total glazed area of solar thermal collectors in operation in 2005 was 527 000 m^2, giving an output capacity of about 369 MW_t.
- **solar thermo-electric energy**: Spain has built up a particular expertise with regard to high-temperature systems, having conducted much research at the Plataforma Solar de Almería in the south-east of the country. The target for 2010 has been raised from 200 MW to 500 MW, with the proviso that the 200 MW limit on the granting of subsidies would have to be removed. It is now envisaged that by 2010 annual generation of electricity by Spanish solar thermo-electric power plants will be in the order of 1 300 GWh.
- **solar-photovoltaic**: the potential resource is estimated at 2 300 MW_p. The following targets have been set for installation during the period 2005-2010: 15 MW_p in isolated installations; 205 MW_p in fixed arrays of less than 100 kW_p; 112 MW_p in tracking arrays of less than 100 kW_p, and 31 MW_p in installations of greater than 100 kW_p. The total increment of 363 MW_p, when added to the 37 MW_p of PV capacity existing in 2004, points to a total peak capacity of some 400 MW in 2010. At end-2005, 27.5% of PV capacity was off-grid and 72.5% grid-connected.

At the beginning of 2003 a 1.2 MW_p solar PV plant covering 70 000 m^2 was opened near the town of Tudela in the Navarre region. The location of the site receives 1 600 kWh/m^2/yr solar radiation; while the central section of the 12 602 PV panels is connected to the grid, the remaining ‘distributed’ area will be used for research on a variety of PV technologies and types of panel.

Sweden

With its electricity generation currently dependent on nuclear and hydro, Sweden's market for solar energy is negligible. As in Norway and Finland, the main application of PV is in the domestic off-grid sector, where installations are sited in remote cabins, campers, caravans and boats.

According to the IEA (PVPS), installed PV capacity in Sweden at end-2005 amounted to 4 237 kW_p, with an annual output of less than 3 GWh during 2005. Of the total capacity, 3 350 kW_p (79%) was off-grid domestic, 633 kW_p off-grid non-domestic and 254 kW_p grid-connected distributed.

From 15 May 2005 to the end of 2007, an investment subsidy of 70% has been made available for the installation of PV systems on public buildings. A cap of 100 million Swedish kronor (approximately € 11 million) applies, corresponding to 2-3 MW of additional PV capacity. This subsidy scheme is reported to have jump-started the Swedish PV market. By the beginning of 2006, one-third of the budget had been applied for, with much interest being shown by the major population centres of Stockholm, Gothenburg and Malmö. As a result of the subsidy, installed PV capacity will jump by 70% by around the end of 2007, and grid-connected building-integrated capacity will increase tenfold.

The market for solar thermal systems has not been strong and by end-2001 it was estimated that a total of 192 157 m^2 had been installed, of which 156 522 m^2 were flat plate collectors, 1 704 m^2 were vacuum collectors and 33 931 m^2 were unglazed collectors. The total glazed area of solar thermal collectors in operation in 2005 was 208 000 m^2, giving an output capacity of about 146 MW_t.

Switzerland

Following the Government's national programme Energy 2000, launched in 1990, Swiss-Energy (also spanning 10 years) is a further programme for the promotion of renewable energy and more efficient use of energy. However, budget reductions introduced in 2003 have cut federal support for pilot/demonstration schemes.

Switzerland has a dedicated national PV programme which covers not only all aspects of RD&D, but also the promotion of the technology and its market deployment. The implantation of PV systems continues to be driven by the 'Solar electricity from the utility' campaign and other green-power publicity. Growth in 2005 was particularly strong, with a 4.3 MW_p increase in the installed capacity of grid-connected systems. Two large systems were completed by Swiss electric utilities: one of 850 kW_p in Berne and the other of 1 MW_p in Geneva.

The Swiss WEC Member Committee reports end-2005 capacity as 26 300 kW_p. IEA-PVPS data indicate that capacity is split 10.8% off-grid domestic, 1.2% off-grid non-domestic, 78.5% grid-connected distributed and 9.5% grid-connected centralised.

The Member Committee, quoting advice from the Federal Office of Energy, shows PV output as rising from the 2005 level of 19.3 GWh to 40 GWh by 2010 and 225 GWh by 2030 – providing a cost-covering feed-in tariff scheme is adopted.

The total glazed area of solar thermal collectors in operation in 2005 was 392 000 m^2, giving an output capacity of about 274 MW_t.

Tanzania

The Tanzanian WEC Member Committee, quoting the Ministry of Energy and Minerals, reports that in recent years solar photovoltaics (PV) have been used for telecommunication, lighting, refrigeration, water pumping and powering other electronic equipment in individual residences, schools, health centres/rural dispensaries and missionary centres. The estimated current installed PV capacity in Tanzania is about 1.2 MW_p, with an annual growth rate of about 20%.

Solar cooking, pasteurising and advanced solar crop-drying technologies are still in their infancy. More research and development is required to address the social and technical barriers that have been identified.

Pilot projects have been established in a number of areas in order to sensitise the communities, and will subsequently be carried out in other parts of the country.

Thailand

Thailand has appreciable solar energy resources in almost all regions, especially in the north and northeast. The average daily solar intensity is 18.2 MJ/m^2. End-2005 installed photovoltaic capacity was 23 700 kW_p.

During the period to 2011, stand-alone PV systems totalling 8.57 MW are scheduled to be installed in remote areas where no transmission line access is planned.

One of the most important research programmes is the project for a PV development laboratory and testing centre, to be completed in 2008.

Current applications of solar energy in Thailand include: solar home systems; battery charging stations; telecommunications; PV for health clinics; ocean navigator systems; greenhouse solar drying; hot water systems; PV for schools and water pumping.

Turkey

Based on meteorological measurements made during 1966-1982, Turkey's average annual number of hours of sunshine is put at 2 640 and its average annual insolation at 1 311 kWh/m^2. More recent research has, however, indicated that these levels could be considerably understated.

The republic's utilisation of its significant solar radiation resource is largely in the form of solar thermal collectors. The market was initiated during the 1970s in response to the growth of the tourism industry and the need for plentiful hot water. The country's energy supply difficulties and the political and economic uncertainties of the 1980s provided further impetus to market development. Although deployment has been extensive - it is estimated that well over 8 million m^2 of flat plate collectors have been installed - the sector has not demonstrated a high degree of advanced technology. Turkish customers have historically preferred simple, inexpensive installations, albeit that this approach has sometimes led to problems of utilisation and maintenance.

It is expected that the solar thermal market will continue to grow, largely through the installation of more roof-top collectors, but also possibly through larger-scale projects, such as winter-season greenhouse heating in the agricultural areas of southern Turkey.

Use of solar PV devices in Turkey has been very largely confined to official installations in remote areas: e.g. telecommunications, forest-fire observation towers and roadside emergency facilities.

Ukraine

The average annual level of insolation is 1 070 kWh/m^2 in the northern regions of Ukraine and 1 400 kWh/m^2 in the southern regions.

The Ukrainian WEC Member Committee states that the potential use of solar energy for energy and heat supply in thousands tons of reference fuel (equal to thousands of tonnes of coal equivalent) is seen as rising as follows: 2005 – 14.6; 2010 – 50.5; 2015 – 145.1; 2020 – 328.0; 2025 – 590.96; 2030 – 927.6.

To achieve the level in 2030, it is planned to bring solar energy capacities up to 2 175 MW, including solar electrical energy up to 1 250 MW with production of 2 010 GWh/yr (0.7 million tons of reference fuel per year), and solar heat energy up to 925 MW (0.2 million tons of reference fuel per year).

Ukraine's main research programmes comprise:

- a programme of state support for the development of non-conventional and renewable energy sources and small hydro and thermal energy up to 2010. (Order of Government (Cabinet of Ministers) of Ukraine, No 1505 of 31 December 1997);
- a development programme for solar energy in Ukraine (being undertaken by the Ministry of Industry Policy).

Examples of solar energy installations include:

a 5 kW PV system for the Institute of Renewable Energy of the National Academy of Sciences; a 10 kW solar heat supply system for the NAS Botanical Garden; a 10 kW system on Zmyyniy Island in the Black Sea; and a 1 kW installation in the Kyiv Polytechnic Institute.

United Kingdom

In part for the obvious climatic reasons, the United Kingdom has not installed solar energy devices to anything like the same extent as its more southerly (and therefore generally sunnier) European colleagues. By the end of 2005, the UK's total PV capacity was 10 877 kW$_p$, equivalent to 0.18 watts per capita, compared with Spain's 1.32 W/capita and Italy's 0.64. Even more striking is the contrast with nearer neighbours such as the Netherlands and Germany. In their cases climatic differences are clearly not so marked, but the disparity in PV deployment is even wider, with Dutch PV averaging 3.12 W/capita and Germany way out ahead with 17.32.

In the UK there has been a Major Photovoltaic Demonstration Programme (MPDP) offering grants for small, medium and large-scale installations, which has encouraged a significant number of new projects. Installed PV capacity grew by about 33% in 2005, with the MPDP providing support for 80% of the new capacity. At the year-end, 91.5% of the UK total of 10.9 MW_p was grid-connected distributed capacity.

The Demonstration Programme ended in March 2006, with the last installations funded by the scheme being completed by March 2007. Future financial support for PV installations will be furnished by the Low Carbon Buildings Programme, part of the Government's new Microgeneration Strategy.

Solar collectors for heating water are used in the UK to a limited extent. In 2005, according to DTI estimates, they contributed 172.4 GWh for heating swimming pools, and 77.1 GWh towards domestic hot water supply. The total glazed area of solar thermal collectors in operation in 2005 was 197 000 m^2, giving an output capacity of about 138 MW_t.

United States of America

Raw solar resources are far in excess of all projected energy demand in the mid-term. Solar insolation levels in the US vary from less than 400 W/m^2 to over 700 W/m^2, depending on latitude, climate (primarily average cloud cover), terrain, and application (that is, using a fixed-angle collector compared to a collector that tracks the sun). However, the USA has approximately 9 million square kilometres of land area.

The United States Energy Association (the WEC Member Committee for the USA) reports that, according to the EIA, central station photovoltaic capacity was 11 000 kW at the end of 2005 and that, on the basis of the stock of equipment in place, there was an estimated 485 000 kW of dispersed PV capacity in operation. Output of electricity from the centralised PV capacity was 15 593 MWh, implying an average capacity factor of approximately 0.16.

Solar thermo-electric capacity at end-2005 is reported as 400.4 MW, producing 534 701 MWh during the year, at a capacity factor of 0.15.

Direct solar heating panels produced a total of 51 652 TJ in 2005.

The aim of the Department of Energy's Solar Energy Technologies Program (Solar Program) is, through public-private partnerships, to 'bring reliable and affordable solar energy technologies to the marketplace'. The Solar Program currently carries out research and development in the fields of PV and CSP systems for electricity generation, and into solar heating systems for producing hot water (or hot air) for domestic, commercial or industrial purposes. The Program is also investigating a form of solar lighting that uses small solar concentrators and fibre optics in combination to provide daylight illumination inside buildings.

Uruguay

Uruguay has a well-developed electricity grid, with about 95% of the population having a connection. The principal applications of solar energy are for water heating and photovoltaics, the latter mainly for lighting.

The Uruguayan WEC Member Committee reports that by the end of 2007, within the framework of the Energy Efficiency Project, UTE (the national electricity company) will complete the installation of 1 000 photovoltaic panels (55 W each) in low-income homes in isolated rural areas.

11. Geothermal Energy

COMMENTARY

COMMENTARY

Introduction

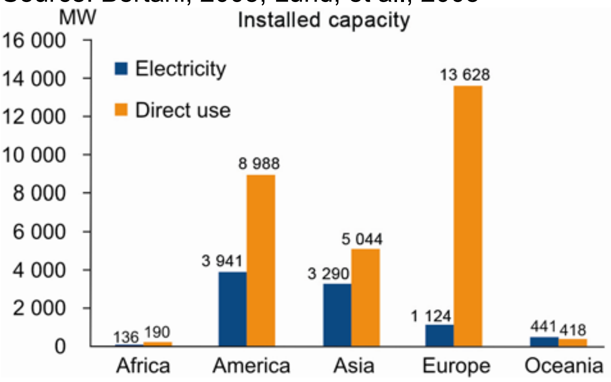
Although geothermal energy is categorised in international energy tables amongst the 'new renewables', it is not a new energy source at all. People in many parts of the world have used hot springs for bathing and washing of clothes since the dawn of civilisation. An excellent book has been published with historical records and stories of geothermal utilisation from all over the world (Cataldi, et al., 1999).

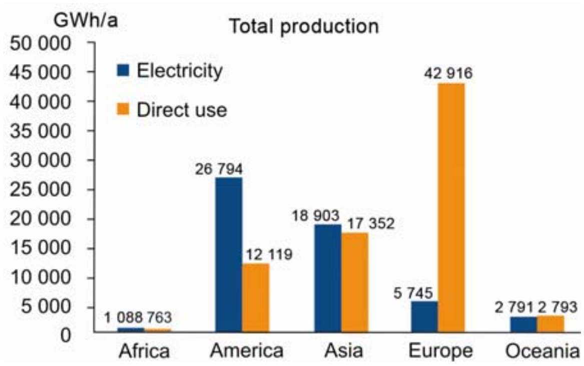
Electricity has been generated by geothermal steam commercially since 1913, and geothermal energy has been used on the scale of hundreds of megawatts for five decades, both for electricity generation and direct use. The utilisation has increased rapidly during the last three decades. Geothermal resources have been identified in some 90 countries and there are quantified records of geothermal utilisation in more than 70 countries. Electricity is produced by geothermal in some 25 countries. Five of these countries obtain 15-22% of their national electricity production from geothermal. In 2004, the worldwide use of geothermal energy was about 55 TWh of electricity (Bertani, 2005), and 76 TWh for direct use (Lund, et al., 2005). Fig. 11-1 shows the installed capacity and the energy produced by geothermal by continent.

Electricity production increased by 16% from 1999 to 2004 (annual growth rate of 3%), and direct use by 43% (annual growth rate of 7.5%). Only a small fraction of the geothermal potential

Figure 11-1 Installed capacity (left) and energy production (right) for geothermal electricity generation and direct use by continent, 2004

Source: Bertani, 2005; Lund, et al., 2005





has been developed so far, and there is ample space for an accelerated use of geothermal energy, both for direct applications and electricity production.

Of the total electricity production from renewables of 2 968 TWh in 2001, 91% came from hydropower, 5.7% from biomass, 1.8% from geothermal and 1.4% from wind. Solar electricity contributed 0.06% and tidal 0.02%. A comparison of the renewable energy sources shows the electrical energy cost to be US$ 0.02-0.10/kWh for geothermal and hydro, US$ 0.04-0.08/kWh for wind, US$ 0.03-0.12/kWh for biomass, US$ 0.25-1.60/kWh for solar photovoltaic and US$ 0.12-0.34/kWh for solar thermal electricity. Heat from renewables is also commercially competitive with conventional energy sources. The current cost of direct heat from biomass is US$ 0.01-0.06/kWh, geothermal US$ 0.005-0.05/kWh, and solar heating US$ 0.02-0.25/kWh (WEA, 2004).

Figure 11-2 Electricity from four renewable energy resources, 2001

Source: World Energy Assessment, 2004

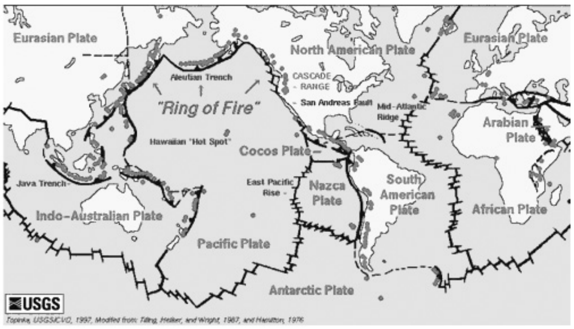
	Operating capacity		Production per year	
	(GW_e)	(%)	(TWh)	(%)
Geothermal	8	24.4	53	53.8
Wind	23	70.1	43	43.7
Solar	1.5	4.6	1.9	1.9
Tidal	0.3	0.9	0.6	0.6
Total	32.8	100.0	98.5	100.0

Geothermal energy is independent of weather conditions, contrary to solar, wind, or hydro applications. It has an inherent storage capability and can be used both for base-load and peak power plants. However, in most cases, it is more economical to run the geothermal plants as base-load suppliers. Fig. 11-2 clearly reflects the variable capacity factors of power stations using the four renewable sources. At end-2001, wind energy was in the leading position with 70.1% of installed capacity, followed by geothermal with 24.4%. Geothermal was, however, the leading electricity producer with 53.8% of total production, followed by wind energy with 43.7%. Geothermal's relatively high share of electricity production reflects the reliability of its plants, which can be operated at capacity factors in excess of 90%.

Geothermal energy has until recently had a considerable economic potential only in areas where thermal water or steam is found concentrated at depths of less than 3 km in restricted volumes, analogous to oil in commercial oil reservoirs. This has changed in the last two decades with developments in the application of ground-source heat pumps using the earth as a heat source for heating or as a heat sink for cooling, depending on the season. This has made it possible for all countries to use the heat of the earth for heating and/or cooling, as appropriate. It should be stressed that heat pumps can be used basically everywhere.

Geothermal energy is independent of weather conditions, contrary to solar, wind, or hydro applications.

Figure 11-3 World map showing the lithospheric plate boundaries
Source: US Geological Survey



Geothermal Resources

Geothermal energy, in the broadest sense, is the natural heat of the Earth. Immense amounts of thermal energy are generated and stored in the Earth's core, mantle and crust. At the base of the continental crust, temperatures are believed to range from 200 to 1 000°C, and at the centre of the earth the temperatures may be in the range of 3 500 to 4 500°C. The heat is transferred from the interior towards the surface mostly by conduction. This conductive heat flow means that temperatures rise with increasing depth in the crust by on average 25-30°C/km. Geothermal production wells are commonly over 2 km deep, but at present rarely much over 3 km. With an average thermal gradient of 25-30°C/km, a 1 km well in dry rock formations would have a bottom temperature near 40°C in many parts of the world (assuming a mean annual temperature of 15°C) and a 3 km well 90-100°C.

Exploitable geothermal systems occur in a number of geological environments. They can be divided broadly into two groups, depending on whether they are related to young volcanoes and magmatic activity or not. High-temperature fields used for conventional power production (with temperatures above 150°C) are mostly confined to the former group, but geothermal fields exploited for direct application of the thermal energy can be found in both groups. The temperature of the geothermal reservoirs varies from place to place, depending on the local conditions.

High-temperature fields. Volcanic activity mainly occurs along so-called plate boundaries (Fig. 11-3). According to the plate tectonics theory, the Earth's crust is divided into a few large and rigid plates which float on the mantle and move relative to each other at average rates counted in centimetres per year (the actual movements are highly erratic). The plate boundaries are characterised by intense faulting and seismic activity, and in many cases volcanic activity. Geothermal fields are very common on plate boundaries, as the crust is highly fractured and thus permeable, and sources of heat are readily available. In such areas magmatic intrusions, sometimes with partly molten rock at temperatures over 1 000°C, situated at a few kilometres depth, heat the groundwater. The hot water has lower density than the surrounding cold groundwater and therefore flows up towards the surface along fractures and where there is permeability.

Most of the plate boundaries are beneath the sea, but in cases where the volcanic activity has been intensive enough to build islands or where active plate boundaries transect continents, there are commonly high-temperature geothermal fields scattered along the boundaries. A spectacular example of this is the ‘ring of fire’ that circumscribes the Pacific Ocean (the Pacific Plate) with intense volcanism and geothermal activity in New Zealand, Indonesia, Philippines, Japan, Kamchatka, Aleutian Islands, Alaska, California, Mexico, Central America, and the Andes mountain range. Other examples are Iceland, which is the largest island on the Mid-

Among the top fifteen countries producing geothermally-generated electricity, there are ten developing countries. Among the top fifteen countries in the direct use of geothermal, six are developing and transitional countries.

Atlantic Ridge plate boundary, and the East African Rift Valley with impressive volcanoes and geothermal resources in e.g. Djibouti, Ethiopia and Kenya.

Low-temperature fields. Geothermal resources unrelated to volcanoes can be divided into four types:

a) resources related to deep circulation of meteoric water along faults and fractures;

b) resources in high-porosity rocks at hydrostatic pressure;

c) resources in high-porosity rocks at pressures greatly in excess of hydrostatic pressure (i.e. ‘geopressured’);

d) resources in hot but dry (low-porosity) rock formations.

These four types are in fact end members, with most natural systems displaying some intermediate characteristics. All of these types, with the exception of type c), can also be associated with volcanic activity. Types c) and d) are not commercially exploited as yet. A comprehensive description of the nature of geothermal systems is given (with diagrams) on the homepage of the International Geothermal Association (www.geothermal-energy.org).

Type a) is probably the most common type for warm springs in the world. These can occur in most rock types of all ages, but are most visual in mountainous regions where warm springs appear along faults in valleys. Warm springs of this type are of course more numerous in areas with a high regional conductive heat flow (with or without volcanic activity), but are also found in areas of normal and low heat flow. The important factor here is a path for the meteoric water to circulate deep into the ground and up again. Areas of young tectonic activity are commonly rich in this type of geothermal spring, such as in Turkey and the Balkan Peninsula.

Type b) is probably the most important type of geothermal resource not associated with young volcanic activity. Many regions throughout the world are characterised by deep basins filled with sedimentary rocks of high porosity and permeability. If these are properly isolated from surface ground water by impermeable strata, the water in the sediments is heated by the regional heat flow. The age of the sediments makes no difference, so long as they are permeable. The geothermal reservoirs in the sedimentary basins can be very extensive, as the basins themselves are commonly hundreds of kilometres in diameter. The temperature of the thermal water depends on the depth of the individual aquifers and the geothermal gradient in the area concerned, but is commonly in the range of 50-100°C (in wells less than 3 km deep) in areas that have been exploited (such as the Paris Basin in France, the Pannonian Basin in Hungary, and several areas in China). Geothermal resources of this type are rarely seen on the surface, but are commonly detected during deep exploration drilling for oil and gas. The widespread low-temperature geothermal resources of China are divided between types a) and b).

Figure 11-4 Top fifteen geothermal countries, 2004
Sources: electricity data, Bertani, 2005; direct use data, Lund, et al., 2005

Geothermal electricity production		Geothermal direct use	
	GWh		GWh
USA	17 917	China	12 605
Philippines	9 253	Sweden	10 000
Mexico	6 282	USA	8 678
Indonesia	6 085	Turkey	6 900
Italy	5 340	Iceland	6 806
Japan	3 467	Japan	2 862
New Zealand	2 774	Hungary	2 206
Iceland	1 483	Italy	2 098
Costa Rica	1 145	New Zealand	1 968
Kenya	1 088	Brazil	1 840
El Salvador	967	Georgia	1 752
Nicaragua	271	Russia	1 707
Guatemala	212	France	1 443
Turkey	105	Denmark	1 222
Guadeloupe	102	Switzerland	1 175

Utilisation

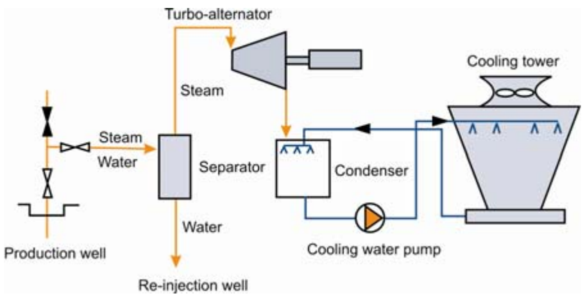
Geothermal utilisation is commonly divided into two categories, i.e. electricity production and direct application. Conventional electric power production is commonly limited to fluid temperatures above 150°C, but considerably lower temperatures can be used with the application of binary fluids (outlet temperatures commonly about 70°C). The ideal inlet temperature into houses for space heating is about 80°C, but by application of larger radiators or the application of heat pumps or auxiliary boilers, thermal water with temperatures only a few degrees above the ambient temperature can be used beneficially.

It is of great interest to note that among the top fifteen countries producing geothermally-generated electricity, there are ten developing countries. Among the top fifteen countries in the direct use of geothermal, six are developing and transitional countries.

Technologies for Electricity Generation

Most commonly, electricity generation takes place in conventional steam turbines (Fig. 11-5). The steam, typically at a temperature above 150°C, goes directly from dry steam wells or, after separation, from wet wells through a turbine which drives the electric generator. After that it goes to a condenser where vacuum conditions are maintained by cooling water. The unit sizes are commonly 20-50 MW.

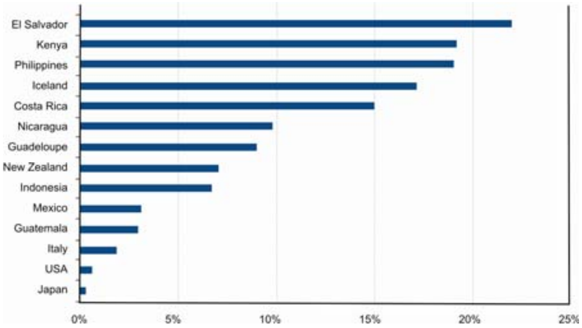
Figure 11-5 A schematic diagram of a geothermal condensing power plant
Source: Dickson and Fanelli, 2003



Binary plants have been gaining popularity in recent years. They utilise geothermal fluids at lower temperatures than conventional plants, in the range 85-170°C. They use a secondary working fluid, usually an organic fluid, which has a low boiling point and high vapour pressure at low temperatures, compared with steam. The fluid passes through a turbine in a similar way as steam in conventional cycles. Binary plants are usually constructed in small modular units of up to a few MW capacity which are linked together. Kalina is a relatively new binary-fluid cycle which utilises a water-ammonia mixture as working fluid. This increases the efficiency of the cycle compared with other binary cycles. A 2 MW

Figure 11-6 Countries with the highest percentage share of geothermal in their 2004 electricity production

Source: Bertani, 2005



Kalina plant has been in operation in Husavik, North Iceland, since 2000.

The efficiency of geothermal utilisation is considerably enhanced by cogeneration plants, compared with conventional geothermal plants. A cogeneration plant produces both electricity and hot water which can be used for district heating as well as other direct uses. A necessary condition for the operation of a cogeneration power plant is that a relatively large market exists for hot water not too far distant from the plant. Iceland, where three geothermal cogeneration plants are in operation, is an example of this. There, the distance of the plants outside the towns is 12-25 km.

Electricity Generation

The top fourteen countries with the highest percentage share of geothermal in their national electricity production are shown in Fig. 11-6. Special attention is drawn to the fact that El Salvador, Costa Rica and Nicaragua are among the six top countries, and Guatemala is in eleventh place. Central America is one of the world´s richest regions in geothermal resources. According to data provided for the World Geothermal Congress in 2005 (Bertani, 2005) geothermal power provides about 12% of the total electricity generation of the four countries. The geothermal potential for electricity generation in Central America has been estimated to be some 4 000 MW_e (Lippmann, 2002). Only a small portion of the geothermal resources in the region has been harnessed so far (under 500 MW_e) and the electricity generated in the geothermal fields is, in all cases, replacing that generated by imported oil.

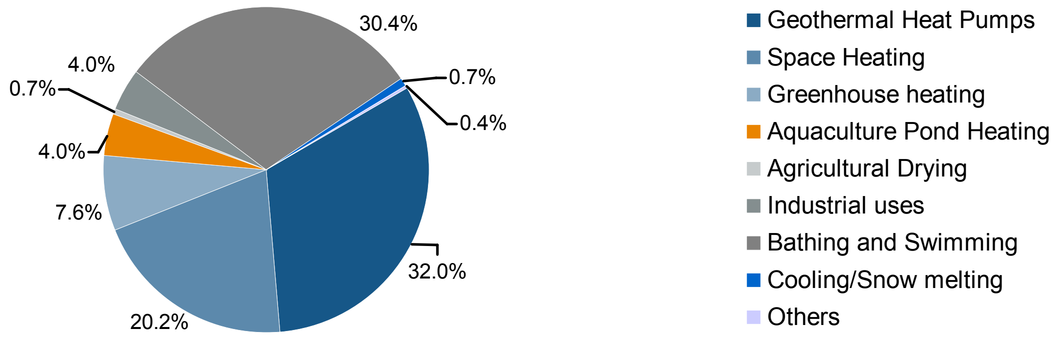
This clearly demonstrates how significant geothermal energy can be in the electricity production of countries and regions rich in high-temperature fields that are associated with volcanic activity. Kenya is the first country in Africa to utilise its rich geothermal resource and can, in the foreseeable future, produce most of its electricity from hydro and geothermal. Several other countries in the East African Rift Valley can follow suit. Indonesia is probably the world´s richest country in geothermal resources and can in the future replace a considerable part of its fossil-fuelled electricity by geothermal.

Direct Utilisation

Fig 11-7 shows the direct applications of geothermal worldwide by percentage of total energy use. The main growth in the direct use sector has, during the last decade, been in ground-source heat pumps. This is due, in part, to the ability of geothermal heat pumps to utilise groundwater or ground-coupled temperatures anywhere in the world.

Space heating is among the most important direct uses of geothermal energy. Preferred water delivery temperature for space heating is in the range 60-90°C and commonly the return water temperature is 25-40°C. Conventional radiators or under-floor heating systems are commonly used, but air-heating systems are also possible. If the temperature of the resource is too low for direct application, geothermal heat

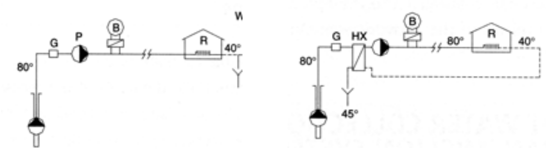
Figure 11-7 Direct applications of geothermal worldwide
Source: Lund, et al., 2005



pumps can be used. This will be discussed in more detail below.

Open loop (single pipe) distribution systems are used for both private schemes and in district heating systems. In this case, geothermal water is used directly for heating and the spent water from radiators is discharged to waste. This type of system is only possible where the water quality is good and recharge into the geothermal system adequate. More commonly, closed loop (double pipe) systems are used. Then heat exchangers are used to transfer heat from the geothermal water to a closed loop that circulates heated freshwater through the radiators. This is often needed because of the chemical composition of the geothermal water. The waste water is disposed of via wells which are called re-injection wells. Closed loop systems are more flexible than open loop systems and they allow substitution of the geothermal water by other energy sources. Both of these two main types of district heating system are shown schematically in Fig. 11-8.

Figure 11-8 Two main types of district heating system
Source: Dickson and Fanelli, 2003



Open loop – single pipe system

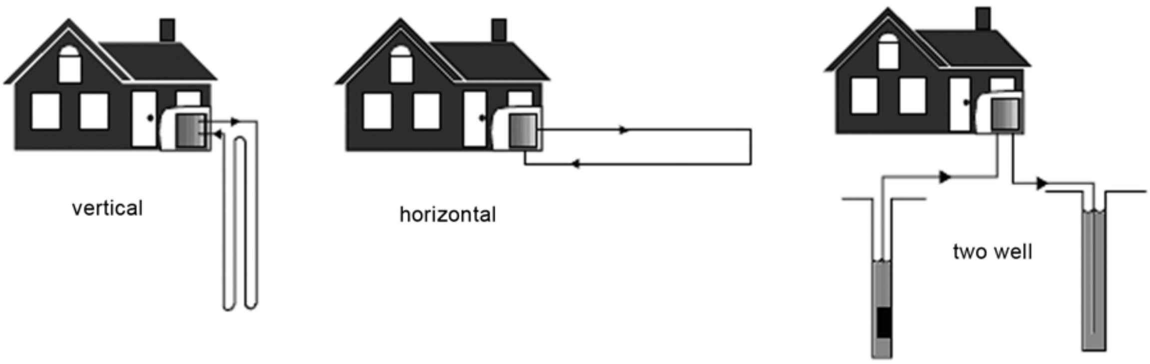
Closed loop – double pipe system

Heat Pump Applications

One of the fastest growing applications of renewable energy is the use of geothermal (ground-source) heat pumps (GHP). This direct use of geothermal energy is based on normal ground or groundwater temperatures which are relatively constant and available anywhere. There are two main types of geothermal heat pumps. In ground-coupled systems a closed loop of plastic pipe is placed in the ground, either horizontally at 1-2 m depth or vertically in a borehole down to 50-250 m depth. A water-antifreeze solution is circulated through the pipe. Thus heat is collected from the ground in the winter and optionally heat is rejected to the ground in the summer. An open loop system uses groundwater or lake water directly as a heat source in a heat exchanger and then discharges it into another well, a stream or lake or even to the ground. In essence heat pumps are nothing more than refrigeration units that can be reversed. In the heating mode the efficiency is described by the coefficient of performance (COP) which is the heat output divided by the electrical energy input. Typically this value lies between three and four (Rybach, 2005).

Worldwide data relating to geothermal heat pump applications were presented at the World Geothermal Congress, Antalya, Turkey, 2005 (WGC-2005). According to those data GHPs account for 54.4% of the worldwide geothermal direct use capacity and 32% of the energy use. The installed capacity reported in 2005 was 15 384 MW_t and the annual energy use 87 503 TJ, with a capacity factor of 0.18 in the heating

Figure 11-9 Closed loop and open loop heat pump systems
Source: Lund, et al., 2004



mode. Based on the size of a typical heat pump unit of 12 kW and the total installed capacity, the total number of installations was estimated to be 1.3 million in 2005, which is over double the number of units reported in 2000.

Fig. 11-10 shows the rapid growth in the worldwide use of geothermal heat pumps, as well as those leading countries which reported at, and after, WGC-2005.

Until recently, almost all of the installations of ground-source heat pumps have been in North America and Europe, increasing from 26 countries in 2000 to 33 countries in 2005 (Lund, et al., 2005). China is, however, the most significant newcomer in the application of heat pumps for space heating. According to data from the Geothermal China Energy Society in February 2007, space heating with ground-source heat pumps expanded from 8 million m^2 in 2004 to 20 million m^2 in 2006. Conventional geothermal space heating in the country had grown from 13 million m^2 in 2004 to 17 million m^2 in 2006. This reflects the policy of the Chinese Government to replace fossil fuels where possible with clean, renewable energy. The *Law of Renewable Energy of China* was implemented in 2006.

Environmental Issues

Geothermal fluids contain a variable quantity of gas, largely nitrogen and carbon dioxide, with some hydrogen sulphide and smaller proportions of ammonia, mercury, radon and boron. The amounts depend on the geological conditions of different fields. Most of the chemicals are concentrated in the disposal water, which is routinely re-injected into drillholes and thus not released into the environment. The level of concentration of the gases is usually not harmful and can be vented to the atmosphere. Removal of hydrogen sulphide released from geothermal power plants is a requirement in the USA and Italy.

The range in CO_2 emissions from *high-temperature geothermal fields* used for electricity production is variable, but much lower than that for fossil fuels. The USA is the leading producer of electricity from geothermal fields with a generation of 18 000 GWh in 2004. Bloomfield, et al. (2003) compared the average values for all geothermal capacity in the USA, including binary power plants. Fig. 11-11 compares the CO_2 emissions from geothermal power plants to those from fossil fuel plants. CO_2 emission values for coal, oil and natural gas plants are calculated using data from the US DOE´s Energy Information Administration. The greenhouse gas emissions of the geothermal plants were reported as follows (in g/kWh): carbon dioxide 91, hydrogen sulphide 85, methane 750, and ammonia 599 (Bloomfield, et al., 2003).

Bertani and Thain (2002) reported on emissions from 85 geothermal plants currently operating in 11 countries and found a weighted average of CO_2 emissions of 122 g/kWh, which compares fairly well with the value of 91 g/kWh reported for the USA plants by Bloomfield, et al. (2003). The survey of Bertani and Thain covered 85% of global geothermal power capacity in 2001.

Figure 11-10 Worldwide growth of ground-source heat pump applications and the leading GHP countries
Source: Lund, et al., 2005

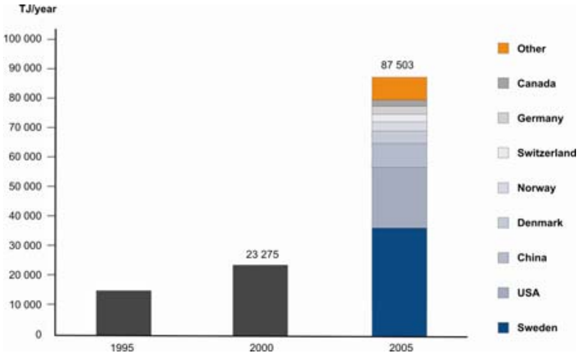
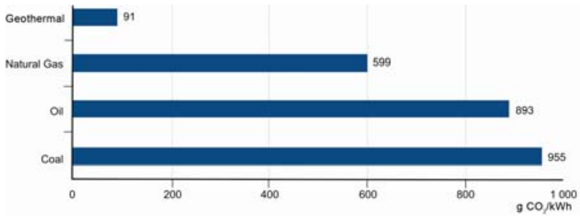


Figure 11-11 Comparison of CO_2 emissions from electricity generation
Source: Bloomfield, et al., 2003



The gas emissions from *low-temperature geothermal resources* are normally only a fraction of the emissions from the high-temperature fields used for electricity production. The gas content of low-temperature water is in many cases minute, as in Reykjavik, where the CO_2 content is lower than that of the cold groundwater. In sedimentary basins, such as the Paris Basin, the gas content may be too high to be released. In such cases the geothermal fluid is kept at pressure within a closed circuit (the geothermal doublet) and re-injected into the reservoir without any de-gassing taking place. Conventional geothermal schemes in sedimentary basins commonly produce brines which are generally re-injected into the reservoir and thus never released into the environment, with consequently zero CO_2 emissions.

Its geothermal district heating makes Reykjavik one of the cleanest capitals in the world. There is no smoke from chimneys and heating with polluting fossil fuels has been eliminated in Iceland. Almost 90% of all houses in the country are currently heated by geothermal water, with the remainder heated by electricity generated from hydro (83%) and geothermal (17%). Geothermal utilisation has reduced CO_2 emissions by some 2 million tonnes annually compared to the burning of fossil fuels. The total release of CO_2 in Iceland in 2004 was 2.8 million tonnes. The reduction has significantly improved Iceland's position globally in this respect and many countries could likewise reduce their emissions significantly through the use of geothermal energy.

Enhanced Geothermal Systems

Enhanced geothermal systems (EGS) have been defined as engineered reservoirs that have been created to extract heat from low-permeability geothermal resources. They comprise a huge amount of useful heat stored in rocks that are technically accessible but lack the natural permeability necessary for heat extraction. The concept is to drill deep injection wells into hot basement rock that has limited permeability and fluid content. Water is injected at sufficient pressure to ensure fracturing or open existing fractures within the developing reservoir and hot basement rock. A production well that intersects the stimulated fracture system is drilled and water circulated to extract heat from the hot basement rock with improved permeability. Considerable effort has been devoted to the development of EGS, both in the United States and Europe. It has been estimated that with a reasonable investment in R&D, EGS could provide 100 GW_e or more of cost-competitive generating capacity in the United States in the next 50 years (The Future of Geothermal Energy, 2006).

New Developments - drilling for higher temperatures

Production wells in high-temperature fields are commonly 1.5-2.5 km deep and the production temperature 250-340°C. The energy output from individual wells is highly variable, depending on the flow rate and the enthalpy (heat content) of the fluid, but is commonly in the range 5-10 MW_e and rarely over 15 MW_e per well. It is well known

In the direct use sector, the potential for geothermal is very large, as space heating and water heating are a significant part of the energy budget in large parts of the world.

from research on eroded high-temperature fields that much higher temperatures are found in the roots of the high-temperature systems. The international Iceland Deep Drilling Project (IDDP) is a long-term programme to improve the efficiency and economics of geothermal energy by harnessing deep unconventional geothermal resources (Fridleifsson, et al., 2007). Its aim is to produce electricity from natural supercritical hydrous fluids from drillable depths. Producing supercritical fluids will require drilling wells and sampling fluids and rocks to depths of 3.5 to 5 km, and at temperatures of 450-600°C. The central science team participants are from Iceland, the USA, Japan, New Zealand, Italy, Germany and France. Other scientists and geothermal experts involved are from Russia, Spain, Norway, the UK, Luxembourg, Greece, Turkey and Portugal. Some 40-50 research proposals and 100-150 scientists and their students are currently active in the project.

The current plan is to drill and test at least three 3.5-5 km deep boreholes in Iceland within the next few years (one in each of the Krafla, Hengill and Reykjanes high-temperature geothermal systems). Beneath these three developed drill fields temperatures should exceed 550-650°C, and the occurrence of frequent seismic activity below 5 km indicates that the rocks are brittle and therefore likely to be permeable. Modelling indicates that if the wellhead enthalpy is to exceed that of conventionally-produced geothermal steam, the reservoir temperature must be higher than 450°C. A deep well producing 0.67 m^3/sec steam (~ 2 400 m^3/h) from a reservoir with a temperature significantly above 450°C could yield enough high-enthalpy steam to generate 40-50 MW of electric power. This exceeds by an order of magnitude the power typically obtained from conventional geothermal wells (Fridleifsson, et al., 2007). Greater energy could thus be obtained from presently-exploited high-temperature geothermal fields from a smaller number of wells. Further information on the IDDP can be obtained on the webpage www.iddp.is

Conclusions

One of the major concerns of mankind today is the ever-increasing emissions of greenhouse gases into the atmosphere and the threat of global warming. There is an international acceptance that a continuation of the present way of producing most of the energy needed - by burning fossil fuels - will bring about significant climate change, global warming, rises in sea level, floods, droughts, deforestation, and extreme weather conditions. The sad fact is that the poorest people in the world, who have done nothing to bring on the changes, will suffer the most. One of the key solutions to avoid these difficulties is to reduce the use of fossil fuels and increase the sustainable use of renewable energy sources. In many parts of the world, geothermal energy can play an important role in this respect.

In the direct use sector, the potential for geothermal is very large, as space heating and water heating are a significant part of the energy budget in large parts of the world. In industrialised countries, 35-40% of total primary

In the electricity sector, the geographical distribution of suitable geothermal fields is more restricted and mainly confined to countries or regions on active plate boundaries or with active volcanoes.

energy consumption is used in buildings. In Europe, 30% of energy use is for space and water heating alone, representing 75% of total building energy use. The recent decision by the Commission of the European Union to reduce greenhouse gas emissions in the member countries by 20% by 2020 compared to 1990 implies a significant acceleration in the use of renewable energy resources. Many EU countries already have a considerable number of geothermal installations. The same applies to the USA where the use of ground-source heat pumps is widespread, both for space heating and cooling. The largest potential is, however, in China. Due to the geological conditions, there are widespread low-temperature geothermal resources in most provinces of China, which are already widely used for space heating, balneology, fish farming and greenhouses during the cold winter months, and also for tap water in the summer.

In the electricity sector, the geographical distribution of suitable geothermal fields is more restricted and mainly confined to countries or regions on active plate boundaries or with active volcanoes. As mentioned earlier, geothermal power stations provide about 12% of the total electricity generation of Costa Rica, El Salvador, Guatemala and Nicaragua. Hydro stations provide 48% of their electricity, and wind energy 1%. With an interconnected grid, it would be easy to provide all the electricity for the four by renewable energy.

With its large untapped geothermal resources and significant experience in the technology, as well as in hydro development, Central America may become an international example of how to reduce the overall emissions of greenhouse gases over a large area. Similar development can be foreseen in the East African Rift Valley, as well as in several other countries and regions rich in high-temperature geothermal resources.

It is very important for the proponents of the various types of renewable energy to work together in order to find the optimal use of energy resources.

Ingvar B. Fridleifsson
United Nations University Geothermal Training Programme,
Árni Ragnarsson
International Geothermal Association[14]

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TABLES

Table Notes

The data shown in Table 11-1 reflect as far as possible those reported by WEC Member Committees in 2006/7, and relate to the year 2005.

When not available from WEC Member Committees, data were drawn from the *Proceedings of the World Geothermal Congress,* Antalya, Turkey, 24-29 April, 2005 and the updated reviews of direct applications (Lund, et al.) and power generation (Bertani) as published subsequently in *Geothermics*. Additional information was provided by the International Geothermal Association and national statistical sources. The WGC data mostly relate to 2004 or early 2005, but will generally be representative of the capacity and output in 2005.

Installed electricity generating capacity in the USA (2 564 MW) reflects the level reported by R. Bertani (quoting J. Lund) as at June 2005. This level is somewhat lower than that published by the U.S. DOE/EIA and reported by the US WEC Member Committee (3 129 MW). The difference is attributable to the treatment of downrated capacity.

The direct use of geothermal energy is not only inherently difficult to quantify but in some instances can be subject to constraints on reporting for reasons of confidentiality, etc. The statistics shown for both capacity and output should therefore be treated as, at best, indicative of the situation in a particular country. As far as possible, direct use includes the capacity and output of geothermal (ground-source) heat pumps.

Annual capacity factors have been calculated on the basis of end-year capacity levels, as average-year data were not available. In general, therefore, the factors shown will tend to be understated.

Table 11-1 Geothermal energy: electricity generation and direct use at end-2005

	Electricity generation			Direct use		
	Installed capacity	Annual output	Annual capacity factor	Installed capacity	Annual output	Annual capacity factor
	(MW_e)	(GWh)		(MW_t)	(TJ)	
Algeria				152	2 417	0.50
Egypt (Arab Rep.)				1	15	0.48
Ethiopia	7			1	15	0.48
Kenya	115	886	0.88	10	79	0.25
Tunisia				25	219	0.28
Total Africa	**122**	**886**	**0.83**	**189**	**2 745**	**0.46**
Canada				422	2 547	0.19
Costa Rica	163	1 145	0.80	1	21	0.67
El Salvador	151	985	0.74			
Guadeloupe	15	102	0.78			
Guatemala	33	212	0.73	2	53	0.79
Honduras				1	17	0.77
Mexico	953	7 299	0.87	156	3 628	0.74
Nicaragua	77	271	0.40			
United States of America	2 564	17 917	0.80	8 670	34 607	0.13
Total North America	**3 956**	**27 931**	**0.81**	**9 252**	**40 873**	**0.14**
Argentina				150	609	0.13
Brazil				360	6 622	0.58
Chile				9	131	0.48
Colombia				14	287	0.63
Ecuador				5	102	0.62
Peru				2	49	0.65
Venezuela				1	14	0.63
Total South America				**541**	**7 814**	**0.46**
Armenia				1	15	0.48
China	28	96	0.39	3 687	45 373	0.39
Georgia				250	6 307	0.80
India				203	1 606	0.25
Indonesia	797	6 085	0.87	2	43	0.59
Japan	535	3 467	0.74	822	10 301	0.40
Korea (Republic)				17	175	0.33
Mongolia				7	213	0.99
Nepal				2	51	0.78
Philippines	1 978	9 902	0.57	3	40	0.38

Table 11-1 Geothermal energy: electricity generation and direct use at end-2005

	Electricity generation			Direct use		
	Installed capacity	Annual output	Annual capacity factor	Installed capacity	Annual output	Annual capacity factor
	(MW_e)	(GWh)		(MW_t)	(TJ)	
Thailand	N	1	0.55	3	79	0.84
Turkey	20	85	0.49	1 229	19 000	0.49
Vietnam				31	81	0.08
Total Asia	**3 358**	**19 636**	**0.67**	**6 257**	**83 284**	**0.42**
Albania				10	9	0.03
Austria	1	2	0.25	1 134	6 872	0.19
Belarus				2	13	0.21
Belgium				64	431	0.21
Bulgaria				110	1 672	0.48
Croatia				114	542	0.15
Czech Republic				205	1 220	0.19
Denmark				330	4 400	0.42
Finland				260	1 950	0.24
FYR Macedonia				62	599	0.31
France	15	95	0.72	308	5 196	0.53
Germany	N	2	0.74	505	3 864	0.24
Greece				75	567	0.24
Hungary				694	7 940	0.36
Iceland	232	1 658	0.82	1 804	24 744	0.43
Ireland				20	104	0.16
Italy	810	5 324	0.75	682	8 916	0.41
Latvia				2	32	0.62
Lithuania				41	121	0.09
Netherlands				254	685	0.09
Norway				600	3 085	0.16
Poland				102	928	0.29
Portugal	18	84	0.53	31	385	0.39
Romania				194	2 841	0.46
Russian Federation	79	85	0.12	308	6 144	0.63
Serbia				89	2 457	0.88
Slovakia				188	3 034	0.51
Slovenia				50	730	0.46
Spain				22	347	0.50
Sweden				3 840	36 000	0.30
Switzerland				582	4 229	0.23

Table 11-1 Geothermal energy: electricity generation and direct use at end-2005

	Electricity generation			Direct use		
	Installed capacity	**Annual output**	**Annual capacity factor**	**Installed capacity**	**Annual output**	**Annual capacity factor**
	(MW_e)	**(GWh)**		**(MW_t)**	**(TJ)**	
Ukraine				11	58	0.17
United Kingdom				10	46	0.15
Total Europe	**1 155**	**7 250**	**0.72**	**12 703**	**130 161**	**0.32**
Iran (Islamic Rep.)				30	752	0.79
Israel				82	2 193	0.85
Jordan				153	1 540	0.32
Yemen				1	15	0.48
Total Middle East				**266**	**4 500**	**0.54**
Australia	N	1	0.29	110	2 968	0.86
New Zealand	434	2 691	0.71	350	9 670	0.88
Papua New Guinea	6	17	0.32	N	1	0.32
Total Oceania	**440**	**2 709**	**0.70**	**460**	**12 639**	**0.87**
TOTAL WORLD	**9 031**	**58 412**	**0.74**	**29 668**	**282 016**	**0.30**

COUNTRY NOTES

The Country Notes on Geothermal Energy have been compiled by the Editors. A wide range of sources have been consulted, including national, international and governmental publications/web sites, as well as the *Proceedings of the World Geothermal Congress*, Antalya, Turkey, 24-29 April, 2005 and the updated reviews of direct applications (Lund, et al.) and power generation (Bertani) as published subsequently in *Geothermics*. Use has also been made of direct personal communications.

Albania

Albania possesses a large low-enthalpy geothermal resource located in three zones. The largest, Kruja, extends from the Adriatic Sea in the north southwards into northwestern Greece. Of the other two zones, Peshkopia lies in the northeast of the country and Ardenica in the coastal area.

The direct use of the available resource has been recognised and utilised for many centuries. Hot springs, often for recreational purposes, have also been incorporated into spa clinics, many as balneological centres. However, possibilities exist for the resource to be used for space heating and heat pumps.

Algeria

With abundant fossil fuel resources, there has historically been little development of the geothermal resource in Algeria. However the New and Renewable Energy Policy of the Ministry of Mines and Energy will help to utilise the resource, which research has shown to exist in the zone to the north of the Tellian Atlas mountains and to the south in the Saharan platform.

Although the area around Biskra has been found to have high-temperature springs, the more than two hundred springs that have been recorded in the northern part of the country are low-temperature. They are used mainly for balneological purposes, although a small amount of greenhouse heating also exists.

Argentina

Argentina is in the forefront of South American utilisation of geothermal resources and in recent years there has been much progress in the knowledge of, and direct use of, the resource. This has undoubtedly been helped by the bill for the Renewable Energies Development Act being passed by the Senators Chamber which states that renewable technologies (including geothermal) will supply 8% of electricity consumption.

High-temperature geothermal heat exists in the western region, along the Andes range and moderate to low-temperature thermal fields have been identified in other parts of the country. In the period between 2000 and 2005 nineteen new areas were studied resulting in seven of them moving to the Development and Production stage, eleven to the Pre-Feasibility stage and one to the Reconnaissance stage.

The seven projects in the Development and Production stage are located in the provinces of Entre Rios, Córdoba and Rio Negro and will supply thermal spas and tourist centres, as part of the Government's drive towards a diversification of the economy.

With the plan of providing further thermal spas, the eleven Pre-Feasibility projects are located in the provinces of Córdoba, Entre Rios, Santa Fe, Misiones and Buenos Aires. In early 2007 the Argentine Ministerio de Economía y Producción reported that the projects were at varying stages of development. Those in Córdoba province (3) were the least well advanced, owing to technological difficulties; projects (2) located in Misiones province had shown considerable progress and drilling had taken place; the status of the projects (4) in Entre Rios province were well-advanced with drilling either under way or completed; thermal drilling of the Santa Fe province project was imminent and drilling of the Buenos Aires province project was due to begin in the near future.

The Reconnaissance stage projects (2) are located in Chubut province but only one, a trout-breeding scheme is progressing well.

Of the currently installed 150 MW_t capacity, 22 MW_t is used for individual space heating, 22 MW_t for greenhouse heating, 7 MW_t for fish farming, 14 MW_t for animal farming, 1 MW_t for snow melting and 84 MW_t for bathing and swimming.

The 670 kW binary-cycle pilot power plant at Copahue went off-line in 1996 but construction of a new station (Copahue II) is currently being considered for the generation of electricity again, either as a 100 MW_e plant or as 2 x 50 MW_e built progressively.

Australia

As a result of the Federal Government's ongoing promotion of renewable energy and the introduction in 2001 of the Mandatory Renewable Electricity Target (MRET), the development of the Australian geothermal resource continues. In mid-2004 the Government published a new policy, *Securing Australia's Energy Future* and reconfirmed its commitment to MRET. The Policy introduced a A$ 500 million Low Emissions Technology Fund which is intended to assist low-emission technologies, resulting in the abatement of greenhouse gases.

A 20 kW experimental electric power plant at Mulka (South Australia) which operated for three and a half years in the late 1980s was scaled up and commissioned in 1992 at Birdsville (Queensland). This 150 kW plant ran until end-1994. After environmental considerations dictated a change in the working fluid, and also after a change of ownership, the plant was put back on line for demonstration in mid-1999. Birdsville continues to produce a net output of 120 kW (after deducting own use of 30 kW) and supplies the town's night time electricity requirements and generally during the winter. Although the town also has access to fossil-fuel generated electricity, an automatic switching system shuts down this additional power system when the geothermal plant is able to satisfy demand.

Geothermal energy is largely used directly, particularly in southeastern Australia. Many public buildings in the city of Portland, Victoria have been heated with geothermal water since 1983 when a district heating system was installed. Additionally, there are a number of locations in Victoria and New South Wales where popular spas, visited by hundreds or thousands of people each year, have been established.

It is believed that the use of ground-source heat pumps (GSHP) continues to grow but the market (both residential and commercial) is largely unmonitored. Nevertheless, the building (40 000 m^2) that houses Geoscience Australia in Symonston, (a suburb of Canberra) has its temperature controlled by 350 bores, making it the largest single GSHP installation. It is also known that many systems have been installed in public and commercial buildings in Tasmania, Victoria and New South Wales.

It has been estimated that Australia's very significant hot dry rock (HDR) resource is sufficient to generate the country's electricity requirement for centuries to come. The current federal renewable energy legislation and also specific HDR laws in New South Wales, South Australia and latterly Queensland are particularly favourable for the development of this resource. Research has found HDR is particularly prevalent in the centre of the country, extending into the northeastern corner of South Australia and the southwestern corner of Queensland. The most advanced project is in the Cooper Basin, northeast South Australia, but other schemes in the state as well as in New South Wales are under way.

Austria

The balneological importance attached to the country's spas together with the restrictions imposed by the Austrian Water Law, have somewhat impeded the progress of development of the geothermal resource. Generally, there has been a lack of public interest and support; the management of spas have expressed concern for the quality of water supplied which could possibly be affected by further and diversified use of the resource and the difficulty of combining different uses at new sites have all contributed to this lack of progress. In the case of the Water Law, it is stated that the groundwater below the land belongs to the landowner and this can be highly problematical when deviated drilling is necessary.

The aggregate installed capacity of 62 MW_t is utilised for direct applications such as district heating (45 MW_t), bathing and swimming (3 MW_t), industrial process heat (2 MW_t), the heating of greenhouses (2 MW_t) and electricity (Organic Rankine Cycle) (11 MW_t).

Two small binary power plants, Altheim and Blumau, were brought into operation in 2000 and 2001 respectively.

In the late 1990s the European Union's THERMIE programme provided support for the Simbach-Braunau scheme, a cross-border joint venture between South Germany and Upper

Austria - one of the largest district heating schemes in Europe. An installed capacity of over 30 MW serves five hundred people with some 9.3 MW of power.

In addition, it has been estimated that there are in the order of 25 000 heat pump installations throughout the country.

Belarus

To a great extent Belarus, with its reliance on fossil fuels, has historically depended on neighbours for its supply of energy and although geothermal heat is available, development of this resource (together with the other renewable energies) is still at a very early stage.

The geothermal resource, underlying most of the country, is mainly located in the Pripyat Trough, in the southeast and the Brest Depression, in the southwest. Some initial exploration work was undertaken in the mid-1950s but it is only in recent years that any use of direct heat has been made. Several small installations (in the region of 500 kW) in the north east and central parts of the country have now been built for the purpose of space heating. During 2005 drilling began for an installation in the town of Brest. It is expected to be completed and tested during the first half of 2007, with a geothermal heat pump supplying a local greenhouse complex. A second installation in the town of Soligorsk is planned.

Since the late 1990s several municipal heat pump systems have been installed to serve Minsk.

Brazil

The utilisation of Brazil's huge low-temperature geothermal resource has until now been extremely small. Much research has been undertaken by the Geothermal Laboratory of the National Observatory since the 1970s and it is thought that high-temperature geothermal heat exists only in the offshore Atlantic islands.

At the present time, the installed capacity (some 360 MW_t) is used directly, largely for bathing and swimming, with just 4 MW_t used for agricultural drying/industrial process heat. The 12 or so systems in place (mostly located in the western-central area and the south) can be classified as BRT (bathing, recreation and tourism), PIS (potential for industrial use and space heating) and TDB (therapeutic, drinking and bathing). The BRT systems total 16 MW_t, the PIS, 343 MW_t and the TDB, 3 MW_t, although currently the PIS element is not being used industrially, but for recreational purposes.

Bulgaria

Different assessments put the number of hydrothermal sources in Bulgaria at between 136 and 154, with about 50 of them having a total of 469 MW_t of proven potential for extraction of geothermal energy. The majority of the waters have been found to be low-temperature at intervals of 20-90^{o}C. Only about 4% of the total capacity has been found to have water hotter than 90^{o}C. The theoretical potential of Bulgaria's geothermal energy amounts to 13 856 TJ/yr with the technical potential put at 10 964 TJ/yr.

There are in the region of 100 MW_t geothermal systems installed in the country, representing some 23% of the currently discovered thermal potential (440 MW_t). Together with the as-yet undeveloped resources, the total capacity of thermal waters could reach from 5 100 l/s to 6 400 l/s. The energy that could be obtained when the temperature is reduced to 15^{o}C is estimated at about 751 MW_t.

Currently, geothermal heat is used entirely for direct purposes: a situation that has persisted since the Romans installed under-floor heating in their hypocausts. Today, individual space heating has the majority share at some 50 MW_t, with air conditioning (10 MW_t), greenhouse heating (17 MW_t), bathing and swimming (26 MW_t) and other uses – aquaculture, and the extraction of chemical derivatives (7 MW_t) - as the remaining shares. A small plant, located on the northern Black Sea coast, has been installed for the production of iodine paste and the extraction of methane.

Since 1999 there has been significant development of ground-source heat pumps (GSHP) utilising the low-grade geothermal heat.

As part of the Bulgarian effort to reduce greenhouse gas emissions, the Government has received a grant (under the Japan Climate Change Initiative Grants Program and administered by the International Bank for Reconstruction and Development), to support the development of geothermal energy projects. Phase I covered the collection of technical data, the detailed analyses of financial and economic aspects of implementation and site case studies. Phase II beginning at end-2005 is covering the detailed planning of eight identified projects and also the study of the further use of GSHP.

Canada

Canada has significant and widespread geothermal potential for heating and cooling purposes. As of 2005, 36 000 geoexchange units have been installed in Canada, with an estimated installed capacity of 396 MW_t, and an energy output of 2 161 TJ in 2005.

A significant example of geothermal technology is the first Deep Lake Water Cooling System installed by Enwave Energy Corporation in Toronto. It has been in operation since 2004, serving several buildings in the city's financial district.

The geography of Canada does not easily lend itself to electricity generated from geothermal resources. There is one small generation project under environmental review in southwest British Columbia.

Chile

There has been interest in geothermal exploration in Chile since the beginning of the 20th century and although in recent years the question of security of energy supply has given the development greater impetus, a higher emphasis on the use of renewable energy generally needs to be instituted prior to further progress.

It has been established that the Chilean Andes has more than 300 hot spring areas, giving the country an estimated high-temperature (over 150°C) potential of some 16 000 MW_t.

In the opening years of the 21st century the Geology Department of the University of Chile together with the National Oil Company (ENAP) and various countries with geothermal expertise undertook a research project in the central-southern areas of the country. Additionally, ENAP has worked with CODELCO (the National Copper Corporation) in the northern and southern regions. The intention of the studies was to establish areas that would be suitable for the generation of electricity.

Statistical data regarding the utilisation of geothermal heat is sparse but at the present time all usage is for recreational purposes (spas and swimming pools). It was stated during 2005 that the National Commission of Energy (CNE) was considering the possibility of installing three 100 MW electricity generating plants within the next ten years.

China

With its move to a fast-growing market economy and increasing environmental concerns, the utilisation of geothermal energy in China continues to increase, albeit with private investment rather than with state funds.

Studies have identified more than 3 200 geothermal features, of which some 50 fields have been investigated and explored. High-temperature resources are mainly concentrated in southern Tibet and western parts of Yunnan and Sichuan Provinces, whereas low-medium temperature resources are widespread over the vast coastal area of the south-east, the North China Basin, Songliao Basin, Jianghan Basin, Weihe Basin, etc.

Historically, the primary development has been in geothermal energy used directly for installations as diverse as space heating, agricultural drying, fish farming, irrigation and earthquake monitoring. However, in recent times there has been much expansion of recreational installations. The term ‘Hot Spring Economy’ has been adopted as a result of the establishment in Beijing of the World Geothermal Natural Science Park and the Geothermal Popular Science Exhibition Centre where all aspects of geothermal energy are demonstrated.

Although recently the major developments have taken place in the localities of Beijing, Tianjin and coastal towns, a development has taken place in the area of the Daqing oil field. It was found that some of the oil and gas exploration wells could supply hot water sufficient for a 310 000 m^2 district heating scheme and furnish warm water for 3 000 dwellings. In total, the country utilises geothermal energy for about 13 million m^2 of space heating.

The development of geothermal power generation has been, by comparison, relatively slow, owing to the large hydro-electric resources in those provinces with high-temperature geothermal resources (Tibet and Yunnan). The largest power complex is located at Yangbajain (Tibet). China's aggregate capacity is approximately 28 MW_e, generating about 100 GWh annually.

The utilisation of ground-source heat pumps forms a very small part of the overall use of geothermal heat. At end-2004 it was reported that 15 units of about 2.5 MW_t were in operation.

Colombia

In the first years of the 21^{st} century, the renewable energies have gained favour to the extent that legal dispositions have been passed in support of their promotion. Although knowledge and understanding of the Colombian geothermal resource is still at an early stage, the Colombian Institute of Geology and Mines (INGEOMINAS) is carrying out inventories of the hot springs in the areas of Cerro Bravo – Cerro Machín Volcanic Complex and Cundinamarca department and also the initial stage of exploration in the areas of the Azufral volcano and Paípa.

Currently, the small use of geothermal heat is confined to bathing and swimming (including balneology).

Costa Rica

The Central American volcanic belt passes through Costa Rica, evidenced by numerous volcanoes and geothermal areas. The fields of Miravalles, Tenorio and Rincón de la Vieja are located in the north-western part of the country and have been studied in detail.

To date, Costa Rica's geothermal resources have been utilised almost entirely for electric power generation. A 55 MW_e single flash condensing unit was commissioned in 1993 at Miravalles, followed soon afterwards by an additional 5 MW_e back-pressure unit. A second 55 MW_e condensing unit came on stream in 1998, and subsequently (in 2000) another 29.5 MW_e back-pressure unit. With the commissioning of a further 18 MW_e unit in December 2003, the total installed capacity now stands at 162.5 MW_e

The Instituto Costarricense de Electricidad (ICE) owns and operates Miravalles, with the exception of the 29.5 MW plant, which operates under a 15-year BOT contract.

Exploration work on the slopes of the Rincón de la Vieja volcano at the Las Pailas and Borinquen geothermal fields has resulted in the discovery of high-temperature fields.

Following the feasibility study for a 35 MW_e plant at Las Pailas, ICE will start construction of the first unit during the second half of 2007. Further drilling will take place prior to a feasibility report for the second unit. It is expected that studies will be completed by 2010; the first unit will be on line in January 2011 and the second by July 2014.

The feasibility study on the Borinquen field was 40% complete when it was halted and exploratory work moved to the Las Pailas field. The two are less than 9 km apart, but it is considered that they are fed by separate reservoirs. The feasibility study is now expected to be completed in 2013, with the first unit scheduled to be on line in November 2018.

In the last 20 years, with the help of the Italian Government and the United Nations Development Fund (UNDP), Costa Rica's low- and medium-temperature resource has been studied. However, at the present time direct use is confined to hotel swimming pools in areas of ecotourism.

Croatia

The considerable Croatian geothermal resource is located in the southeastern and northeastern areas of the country and although usage is increasing, it is still at a very low level.

There are 28 reservoirs in the country, with a total potential of about 1 000 MW_t. Of these, 18 (representing some 114 MW_t) have been exploited for direct-use purposes (balneology, recreation and space heating).

As the acceptance and adoption of renewable energies become a reality, it is foreseen that there will be an increased use of geothermal energy within Croatia. It is planned to install a 4.4 MW_e power plant in Velika Ciglena by 2010, with an expansion to 13.1 MW_e by 2015.

Czech Republic

Geothermal energy has been little used, and then only directly (in spas and swimming pools), for over a century. However, with a view to the resource being incorporated within the national energy policy (to 2020), it has now received detailed study.

The Czech Republic's considerable potential has been categorised into high-temperature, hot dry rock (HDR) and low-temperature resources. There is thought to be high-temperature potential for 10 MW_e of electrical generation and 25 MW_t of heat production; a total HDR potential of 3 388 MW_t, based on boreholes in 847 areas, each producing 4 MW_t; and a low-temperature potential that has been estimated at 8 750 MW_t (dry rock) and 2 390 MW_t (groundwater).

More than 10 000 small (20 kW) geothermal heat pumps are installed throughout the country, providing some 200 MW_t of heat energy in residential buildings, hotels, small commercial buildings and swimming pools. A larger (1 MW_t) heat pump is providing warm water for the Prokop ore mine. Research is being undertaken for the further installation of heat pumps for district heating, recreational and industrial uses, and of an electrical power plant.

Denmark

With the Government's positive attitude towards the utilisation of the country's low-enthalpy resource, there has been an increased usage during the first years of the 21st century, which is expected to continue. It is estimated that there is a sufficient resource to supply heat to several towns for hundreds of years.

There are presently two district heating plants in operation. The first, at Thisted (northern Jutland) began operating in 1984. In 1988 it was enlarged to 4 MW_t and again to 7 MW_t in 2000-2001. The second, a 14 MW_t plant at Margretheholm, Copenhagen, started operating in 2004.

Additionally, approximately 250 groundwater-based heat pumps and 43 000 other types of pump (about 10%-20% of which are vertical closed-loop), totalling 309 MW_t , are in operation.

DONG, the Danish energy company, working in conjunction with the Geological Survey of Denmark and Greenland (GEUS), has in recent years carried out a re-evaluation of the country's geothermal potential.

With a view to the installation of further district heating plants and geothermal water production, DONG is currently in discussions with potential clients on a co-ownership basis (there is no public funding available for geothermal projects).

Ecuador

Exploration of the Ecuadorean geothermal potential was begun during the 1970s in order to establish the extent of both high-temperature and low-temperature resources. Despite follow-up prefeasibility studies on the former and prefeasibility studies on the latter, plans for industrial and direct uses were found to be uneconomic.

At the present time geothermal power supplies only a small amount of energy for direct-use purposes. Some 5 MW_t of installed capacity is used for recreation and balneology. The country's energy supply is entirely satisfied by hydroelectricity and fossil fuels, but with Government plans to develop indigenous resources (both conventional and renewable), it has been stated that the role of geothermal is set to increase. Higher oil prices and increasing energy demand may well provide the impetus to completely survey, map and reassess the country's potential.

El Salvador

Like Costa Rica, El Salvador lies on the Central American volcanic belt and there is thus a plentiful geothermal resource. The main emphasis has been on using the resource for power generation and although a potential exists for the direct use of geothermal (drying grains and fruit), it has not yet been developed.

Geothermal energy accounts for over 20% of El Salvador's electricity output. In 2005, power generation from the Ahuachapán and Berlín geothermal facilities was 985 GWh.

Of the 151 MW_e of geothermal capacity currently installed in El Salvador (95 MW_e at Ahuachapán, and 56 MW_e at Berlín), only about 124 MW_e is reported to be actually available (72 MW_e at Ahuachapán and 52 MW_e at Berlín).

Both the Ahuachapán and Berlín plants are due for expansion. The optimisation of the Ahuachapán plant is under way with 17 MW_e successfully completed by end-January 2007. Work continues on the drilling of a new production well and the necessary analysis is being undertaken for a more efficient use of the additional steam. At the beginning of 2007 it was reported that a 40 MW_e third condensing unit at the Berlín plant was in a reliability testing phase and initiation of commercial operation was expected in February 2007. A 5.5 MW_e binary unit was expected to come on-line in March 2007.

Research is under way on the exploration of the San Vicente and Chinameca fields.

If all plans come to fruition, geothermal capacity could total in excess of 210 MW_e by 2010.

Ethiopia

Ethiopia is one of a minority of African countries possessing geothermal potential. Considerable resources of both high- and low-enthalpy geothermal have been located in the Ethiopian Rift Valley and in the Afar depression. Exploration that began in 1969 has, to date, revealed a potential that could possibly generate more than 1 000 MW_e of electricity.

In mid-1998 the 7.23 MW_e Aluto-Langano geothermal plant became operational. It became the first geothermal power plant in Africa to use integrated steam and binary power technology. The plant has experienced operational difficulties, owing to problems with field and plant management skills, but it is hoped that in time these can be overcome.

In addition to the Aluto-Langano geothermal field, the other areas that have been explored are Corbetti and Abaya in the Lakes District, Tulu-Moya, Gedemsa, Dofan, Fantale, Meteka, Teo, Danab in the Southern Afar region and Tendaho and Dallol in the Central Afar region. The exploratory investigations are at different stages of development, ranging from advanced exploration to reconnaissance. Three deep and three shallow exploratory wells have been drilled at Tendaho, four of which are productive.

The country is heavily dependent on petroleum fuels for transport and some electricity generation, biomass for household cooking and lighting and an erratic hydro supply for the remaining electricity generation. If the financial difficulties that research often experiences can be solved, Ethiopia's geothermal potential could certainly assist in providing base-load electricity generation.

France

There are only low-enthalpy geothermal resources in metropolitan France; high-enthalpy geothermal resources are found in France's overseas departments.

The resources are found in two major sedimentary basins: the Paris Basin and the Aquitaine Basin in the southwest. Other areas (Alsace and Limagne) have geothermal potential but it cannot be so readily utilised.

Although the first French geothermal district heating plant was constructed in 1969 in the

Paris region, the main development of geothermal energy began following the oil crises of the 1970s. Development continued throughout the 1980s, culminating in nearly 100 exploration wells being brought into operation. However, the 1990s saw a diminution of interest in geothermal energy and approximately one-third of the plants were closed. The installed capacity is mainly used for space heating (80%+) but also greenhouse heating, fish farming and bathing and swimming.

For a considerable number of years France's low-enthalpy resources have been utilised by heat pump installations but the 2004 Energy Law together with support from EDF (French Electricity Board) and ADEME (French Agency for Environment and Energy Management) has given greater impetus to the development, particularly in the Paris area. It has been estimated that by 2010 some 40 000 heat pumps per year will have been installed in single-family houses.

Since the 1980s the French authorities have supported research into the potential of HDR. Work began at Soultz-sous-Forêts (northeastern France) in 1987 and based on the success of tests and drilling to a depth of 3 900 m (1987-1997), the next phase (1998-2001) was planned. During this period the drilling was extended to 5 000 m and further tests were conducted. Long-term circulation testing continued during Phase I (2001-2004) and during Phase II (2005-2008) it is expected that a 1.5 MW_e power plant will be installed followed by the planning and installation of a 6 MW_e plant.

An Arrêté for the long-term investment in electricity generation was passed on 7 July 2006. As far as geothermal energy is concerned the law includes a target for an additional 90 MW_e capacity by 2010. By end-2015, the target is for a total of 200 MW_e to have been installed.

Georgia

Geothermal resources are prevalent throughout the area of the South Caucasus and are utilised intensively in Georgia. However, development has been slow in recent years despite the fact that foreign aid has been available to assist with the country's difficult energy supply situation.

In 2002 it was estimated that total availability of geothermal water exceeded 100 000 m^3/day. To date, the main use has been for district heating schemes, the most important of which is in the Tbilisi area (10.6 MW_t).

The first stage (3 MW_t) of a plan for the Zugdidi-Tsaishi field was due for completion in 2005. Ultimately it is hoped that a district heating scheme of 100 MW_t will be completed in 2008-2009.

A project in the resort of Tskhaltubo foresees using a heat capacity of 40 MW_t for balneological purposes (by means of heat pumps).

Germany

Germany does not possess high-enthalpy steam reservoirs. Its geothermal resources are located in the North German sedimentary basin, the

Molasse Basin in southern Germany and along the Rhine graben.

Nevertheless, the country's geothermal resource has played a role in Germany's energy supply in recent years. By end-2004 total installed capacity for direct thermal use was 505 $MW_{t,}$ of which 80% was derived from 30 000 decentralised heat pumps (estimated to represent in the region of 400 MW_t) and the remaining 20% from 30 centralised systems (of which, 3% was attributable to individual space heating; 86% to district heating and 11% to bathing and swimming).

Germany's 2000 Renewable Energy Act (EEG) was revised in August 2004 and it is expected that the increase in remuneration for the feed-in allowance from €0.089 to 0.15 per kWh for geothermal energy will lead to greater development than hitherto. The first German geothermal power plant (230 kW_e) was inaugurated at Neustadt-Glewe in November 2003 to provide electricity for 500 households.

The Geothermische Vereinigung (GtV) is promoting the installation of the 1 GW_e Programme from enhanced geothermal systems (for example, HDR) and deep hydrothermal resources.

Already there are two power plants using HDR in development: Groß Schönebeck and Bad Urach, and plans for converting the heat of deep hot aquifers to power at Offenbach, Speyer, Bruchsal and Unterhaching. These projects are being supported by the Federal Government's Zip-Programme (Zukunfts-Investitions-Programm).

In the period 2005-2010 it is expected that 15 projects will come to fruition, providing an additional 126 MW_t of thermal capacity and 18 MW_e of electric power.

Greece

Generally, geothermal energy has encountered opposition from the local population (chiefly the inhabitants of the islands involved) because of the lack of an appropriate introduction and public relations policy by DEI, the Greek public power corporation. A 1984 law brought the exploration and exploitation of geothermal energy under the regulation of the 'mining exploration decree'; a law passed in 2003 replaced it but kept the regulation; the Development Law of 1998 favoured investments for electricity production and generation from renewable energy, but the legislation has not led to a high level of development. However, the first years of the 21st century have seen progress made in the utilisation of the geothermal resource, especially with the rise in heat pump installations.

High-enthalpy geothermal fields occur in the islands of Milos and Nisiros, which are located in the South Aegean volcanic arc. DEI attempted to install a prototype electrical generating unit of about 2 MW_e in the mid-1980s, but the whole project was eventually stopped because of operational problems (mainly due to inadequacies in the system's desalination technique) and consequently opposition from the local population. There is currently no electricity generation from these two fields because of the opposition of the local people.

Low-temperature geothermal fields occurring in structurally active sedimentary basins have a considerable potential. A small proportion of this heat resource is currently utilised, with an installed capacity of about 75 MW_t for space heating, greenhouse and soil heating, bathing and spas, industrial uses, fish farming, cultivation of spiroulina and geothermal heat pumps.

Research conducted by the Institute of Geological and Mineral Exploration (IGME) has discovered many new areas of geothermal potential in the northern regions of Macedonia and Thrace, the Aegean Islands and the northwestern region of Epirus and despite the lack of fast growth, there are several projects under development. These include an 80 000 m^2 heating and cooling scheme for the Macedonian regional airport and various heating/cooling systems for further space heating, greenhouse heating and fish farming.

Guadeloupe

The double-flash plant at La Bouillante in the French Overseas Department of Guadeloupe is at present the only example of the island's geothermal energy being utilised for electricity production. The plant was commissioned in 1985 but was closed between 1992 and 1996.

The French Agency for Environment and Energy Management (ADEME) contributed to the development of the Bouillante high-enthalpy field by supporting 20% of the cost of drilling new wells.

Following the rehabilitation of Bouillante 1, a 5 MW_e double-flash unit, in 1996, the plant was able to supply 2% of the island’s electricity supply in 1998. Extensive exploration of the Bouillante field ensued and led to the drilling of three new production wells and a plan to construct Bouillante 2, an 11 MW_e unit some 400 m from the original plant. Bouillante 2 was put into service in 2005 and currently some 10% of electricity generation is supplied by the geothermal resource. Pre-feasibility studies for Bouillante 3 began in 2004 with the aim of geothermal power supplying up to 20% of the island’s electricity in the future.

Guatemala

Guatemala's Instituto Nacional de Electrificación (INDE) has five geothermal areas for development. All five (Zunil, Amatitlán, Tecuamburro, San Marcos and Moyuta) lie in the active volcanic chain in southern Guatemala. INDE has conducted both investigative work and development of geothermal power since 1972. It has been estimated that Guatemala’s geothermal resource could supply 20% of the country’s electricity supply. However, at the present time, only about 3% is derived from geothermal power. The 2004 law, Incentives for the Development of Renewable Energy Projects (which provides a favourable tax regime), together with help from the Global Environment Facility (GEF) and various other agencies, will provide the basis for growth in forthcoming years.

The first geothermal power plant in the country was constructed in the Amatitlán area; electricity was produced from a 5 MW_e back-pressure plant for a period of three years (from October 1998), during which time the field was evaluated. The Amatitlán field is again producing electricity from a 5 MW_e unit and also supports the direct use of geothermal energy, in the form of using steam for drying concrete blocks and a fruit dehydration plant. It is estimated that the area has a total potential of 200 MW_e.

A second geothermal plant (in the Zunil I field) with a running capacity of 24 MW_e has been operating since July 1999. Following INDE's exploratory drilling work, a contract was signed with Orzunil I for the private installation and operation of the plant. Until 2019 the company will buy steam from INDE and sell power to the national grid. Exploratory drilling in the Zunil II field has shown that it possesses 4 MW_e proved capacity and Zunil I has been found to have a potential capacity of 50 MW_e.

Hungary

Hungary possesses very considerable geothermal resources and it has been estimated that the country has the largest underground thermal water reserves and geothermal potential (low and medium enthalpy) in Europe.

To date, there has been no utilisation of geothermal energy for the production of electricity. The principal applications of geothermal power used directly are for balneological purposes, greenhouse heating, space heating, industrial process heat and other uses. It has been reported that geothermal heat pumps represent an additional 4 MW_t.

There are around 3 000 abandoned oil industry exploration wells that may potentially be transformed for geothermal use. In late-2006 it was announced that the Hungarian Oil and Gas Company (MOL) was working in conjunction with Enex of Iceland and Green Rock Energy of Australia, and with support from the World Bank's Geothermal Energy Development Fund (GeoFund) would be undertaking a pre-feasibility study on the possibility of building a 2-5 MW_e geothermal power plant at Iklódbördöce in western Hungary. Drilling is taking place in disused hydrocarbon exploration wells. The plant would supply its surplus heat for agricultural, industrial purposes and district heating.

Iceland

Geothermal energy resulting from Iceland's volcanic nature and its location on the Mid-Atlantic Ridge has been utilised on a commercial scale since 1930. The high-temperature resources are sited within the volcanic zone (southwest to northeast), whilst the low-temperature resources lie mostly in the peripheral area. A realistic assessment of Iceland's potential for electricity production has been put at 20 TWh annually, after taking into account economic factors, environmental considerations and technological elements.

Iceland’s total annual primary energy consumption was 550 GJ per capita in 2006 - amongst the highest in the world. Geothermal energy provides about 55% of the total primary energy supply while the share of hydropower is 16%, oil 26% and coal 3%. The principal use of geothermal energy is for space heating, where about 89% of all energy used for house heating comes from geothermal resources. There is a total of 26 municipally-owned geothermal district heating systems located in the country, the largest of which is Energy Reykjavik, serving 190 000 people. In addition to the heating of houses, direct use of geothermal energy is made for swimming pools, snow melting, industrial use, greenhouse and fish farming. In 2005 total direct heat use was 23 600 TJ from an installed capacity of 1 800 MW_t.

In recent years there has been an expansion in Iceland's energy-intensive industrial sector and thus a considerable increase in electricity demand. This has been met partly by increasing geothermally-produced electricity. The total capacity of geothermal power plants has increased from 50 MW_e in 1998 to the 2006 level of 422 MW_e. Of 9 925 GWh total electricity generation in 2006, 2 631 GWh or 27% came from geothermal energy, 73% from hydro and a negligible amount from fossil fuels.

Two co-generation power plants are in operation. The Svartsengi energy plant, in operation since 1977 has a capacity of 200 MW_t for hot water production and 46 MW_e for electricity generation, of which 8.4 MW_e comes from binary units using low-pressure waste steam. The effluent brine is disposed of in The Blue Lagoon, a bathing and balneological facility which is becoming a major tourist attraction. A new 30 MW_e generator is being installed at Svartsengi, with completion scheduled for the end of 2007.

At the Nesjavellir energy plant there is an installed capacity of 250 MW_t for hot water production and 120 MW_e for electricity production. The primary purpose of the plant is to provide hot water for the Reykjavik area, 27 km away.

Two conventional geothermal power plants are in operation: Krafla, a 60 MW_e double-flash condensing plant and Namafjall a 3 MW_e back-pressure system. At Husavik generation of electricity began by installing a binary plant of the Kalina type. In generating 2 MW_e of electricity, the geothermal water is cooled from 120ºC to 80ºC. The water is then used for district heating of the town.

It is planned to add a further 40 MW_e to the plant at Krafla and a new plant in the same area is being considered.

Two new power plants began operating in 2006: the first, Reykjanes, 100 MW_e (2 x 50 MW_e) in May, and the second, Hellisheidi, 90 MW_e, in October.

Although the growth of space heating has been fairly slow in recent years, a distinct increase of geothermal’s share (from 89% to 92%) is foreseen, owing partly to demographic movement and partly to further exploration for sources of geothermal heat.

India

It has been estimated by the Geological Survey of India that the geothermal potential is in the region of 10 000 MW_e, widely distributed between seven geothermal provinces. The provinces, although found along the west coast in Gujarat and Rajasthan and along a west-southwest – east-northeast line running from the west coast to the western border of Bangladesh (known as SONATA), are most prolific in a 1 500 km stretch of the Himalayas.

The resource is little used at the moment but the Government has an ambitious plan to more than double the current total installed generating capacity by 2012. This would be achieved by utilising both conventional fossil fuels and the range of renewable energies at India's disposal (bioenergy, hydro, geothermal, solar and wind).

The Tattapani field in the far northwest of the Himalayas is estimated to have a potential of 1 MW_e and if this could be developed it would substantially benefit the isolated villages in the mountainous areas.

Direct utilisation is almost entirely for bathing and balneological purposes but greenhouse cultivation of fruit could be developed extensively in the future.

Indonesia

The islands of Indonesia possess enormous geothermal resources: geological surveys conducted by the Government have identified as many as 255 prospects, of which 70 are specified as high-temperature reservoirs with an estimated total resource potential of nearly 20 000 MW_e. Of this potential about 48% is in Sumatra, 30% in Java-Bali, 7% in Sulawesi and 15% in other islands. Taken together, the low- and high-enthalpy potential totals some 27 000 MW.

A very small amount of geothermal energy is used directly for bathing, balneology and swimming. In recent years research has been undertaken into the possibility of using geothermal heat for the sterilisation of the growing medium for mushrooms.

The effects of Indonesia's financial crisis in 1997 are still being felt. Prior to this time the Government had planned to install some 3 000 MW by 2006 but by end-2004 the country had increased its installed geothermal electric power generation capacity to 797 MW_e (operationally capable of at least 807 MW_e). This latter figure includes currently operating facilities with a capacity of 330 MW_e at Gunung Salak, 140 MW_e at Kamojang, 145 MW_e at Darajat, 110 MW_e at Wayang Windu, 2 MW_e at Sibayak, 20 MW_e at Lahendang and an additional 60 MW_e at Dieng.

It remains the Government's policy to significantly alter the fuel mix of electricity generation by increasing the use of coal, geothermal energy and hydro power and thus reducing the use of oil and gas. To this end it plans to have 6 000 MW_e of geothermal generating plant installed by 2020.

Iran (Islamic Republic)

Iran's geothermal potential is embodied in low- to medium-enthalpy resources found in provinces fairly widely distributed across the country. However, two provinces, Damavand in the north-central area and Maku-Khoy in the far north west, are likely to be the most productive.

The Ministry of Energy instituted a study of the geothermal resources in 1975 and a proposal for power generation from the Meskinshahr field (in the Sabalan prospect - also in the northwest) followed. Drilling of three exploratory wells began during 2002 and work continues on research and development.

Traditionally, geothermal heat has been used directly for recreational and balneological purposes but currently study is being undertaken on the feasibility of using the heat for greenhouses, aquaculture and space heating.

The country is extremely well-endowed with low-cost fossil fuels and this has proved a disincentive to the development of the renewable energies. However, the Government is showing a growing interest in progressing renewable energy in order to meet fast-growing national energy demand.

Ireland

There are no high-temperature geothermal resources in Ireland and all instances of low-temperature potential are only suitable for direct utilisation. To date, only one of the 42 warm springs located in the east and south of the country has been exploited, for heating a swimming pool.

The country does however possess an adequate supply of groundwater sources suitable for heat pumps. Since the late 1990s, the market has grown significantly so that now more than 1 500 domestically installed systems (typically, 12-14 kW) exist. This trend is expected to continue. Additionally, more than 30 large-scale heat pumps have been installed in commercial buildings. In total, heat pumps represent some 20 MW_t of installed capacity.

Israel

In recent years progress on the development of Israel's low-enthalpy resources has been relatively slow. Geothermal heat has been utilised directly for fish farming, spas and greenhouses.

Italy

Italy is one of the world's leading countries in terms of geothermal resources. The high-temperature steam-dominated reservoirs lie in a belt running through the western part of the country from Tuscany to Campania (near Naples). Commercial power generation from geothermal resources began in Italy in 1913 with a 250 kW unit. Subsequently the main emphasis has been on the production of power rather than on direct use of the heat.

Following the limited development of resources during the first half of the 20th century, it was the second half of that century that saw rapid growth. By end-2004, total Italian installed geothermal capacity stood at 790.5 MW_e, comprising operational units in the areas of Larderello, Travale-Radicondoli and Mount Amiata. The Italian WEC Member Committee reports that capacity at end-2005 was 810 MW_e.

Geothermal plants are eligible for various kinds of government support, including national mandatory quotas and tradable green certificates, renewable energy certificates, guarantees of origin and dispatching priority.

Power generation potential is almost fully tapped, so major efforts are being made in deep drilling and in keeping output at 5 500-6 000 GWh/yr through re-injection and well stimulation.

In 2004 an exploration study began in the areas of Larderello-Radicondoli-Montieri. This includes the drilling of eleven wells to depths of 3 000–4 000 m. However, opposition from various local communities has hindered progress. Nevertheless it is foreseen that another 100 MW_e of capacity could be installed by 2010.

In addition to Italy's geothermally-powered electricity generation, the country also utilises its resources for direct purposes. Of the 600 MW_t of installed capacity at end-2004, 58 MW_t are used for industrial space heating, 74 MW_t for district heating, 94 MW_t for greenhouse heating, 92 MW_t for fish farms, 10 MW_t for industrial process heat, 159 MW_t for bathing and swimming and 120 MW_t for ground-source heat pumps.

It was estimated that in 2005 some 6 000 heat pumps were in operation, with an installation rate of some 500 per annum. In the north of the country the heat pump market is destined to grow. A plan was announced in 2005 for 5 x 50 MW_t district heating schemes to be installed in Milan, each serving 30 000 inhabitants.

Japan

Japan has a long history of geothermal utilisation, both direct and for power generation. It is one of the world leaders in terms of generation of electricity. The first experimental power generation took place in 1925, with the first full-scale commercial plant (23.5 MW_e) coming on-line at Matsukawa, in the north of the main island of Honshu, in 1966. Following each of the two oil crises, development of Japan's geothermal resources was accelerated and by end-1984, 314.6 MW_e capacity had been commissioned. Growth continued and unit size decreased as technological improvements occurred. By end-2003, installed capacity stood at 535.25 MW_e (consisting of 20 units at 18 locations). The existing plants are all located in the Tohoku region of northern Honshu and on the southern island of Kyushu.

The country's geothermal potential is estimated to be in the order of 24.6 GW_e. Only a small fraction of this potential has been used to date and until ways of tapping Japan's deep resources can be developed, this situation will prevail. In 2000 the planned government deregulation of the electricity sector took place. This was followed in 2003 by the Special Law

Concerning the Use of Renewable Energy by Electric Utilities – a method for the encouragement of generation from renewable energies by means of a renewable portfolio standard (RPS). In the case of geothermal, the RPS is confined to binary-cycle plants.

In recent years, development of electricity generating plant has been slow but at the beginning of 2004 a 2 MW_e power unit was installed at the Hatchobaru power station – the first binary-cycle plant in Japan.

Direct use of geothermal hot water has a long tradition in Japan, where enjoyment of natural baths (more than 25 000) is a national recreation. In 2005 it was estimated that total installed capacity for direct use totalled more than 400 MW_t (excluding recreational hot-spring bathing). Of the total, hot water supply and swimming pools account for 26%, space heating 25%, snow melting 23%, greenhouse heating 11%, air-conditioning/cooling 10% (70%-30% split), fish breeding 4%, ground heat uses (including heat pumps) 1% and industrial and other uses negligible.

Jordan

Jordan possesses considerable thermal water resources spread along the Rift Valley, in addition to thermal wells in the Central and the Eastern Plateau.

Several studies on the evaluation and assessment of these resources have been conducted by the Natural Resources Authority (NRA). The results have shown that the thermal resources are of the low-enthalpy type and range in temperature from 30^{o}C to 60^{o}C. Their optimum use is for space heating, greenhouses and fish farming.

At the present time the geothermal resource is used directly in spas and for bathing and balneological purposes – installed capacity stood at some 153 MW_t at end-2004. The NRA plans to further diversify direct uses into the winter heating of greenhouses, the provision of heated water in winter for fish farming and refrigeration by absorption. It has been reported that, in cooperation with Japan (and funded by a Japanese Policy and Human Resources Development [PHRD] Grant through the World Bank), Jordan is currently implementing a study on the technical and economic evaluation of geothermal drilling data for energy applications.

Kenya

The country has a high dependence on hydropower for electricity generation (approximately 60%), but the unreliability of the water resource poses a problem, particularly for the industrial sector's power supply and also more generally leads to the purchase of expensive and polluting fossil fuels. With its substantial geothermal resource, the Kenyan Government has expressed its commitment to support the further development of this potential.

It is often reported that Kenya possesses a geothermal potential in the region of 2 000 MW_e (Kenya Electricity Generating Company

[KenGen] states that research has shown a potential of more than 3 000 MW_e). The fourteen prospects that have been identified lie in the Rift Valley but to date wells have been drilled at only two sites. These are situated at Olkaria near Lake Naivasha (about 120 km north-west of Nairobi) and Eburru, but only the former has been exploited.

KenGen's Olkaria I was Africa's first geothermal power station when the first unit came into operation in mid-1981, with an initial installed net capacity of 15 MW_e. Two more 15 MW_e units were added in 1982 and 1985.

The 2 x 35 MW_e units of the Olkaria II plant (African's largest geothermal power plant and co-financed by the World Bank, the European Investment Bank, KfW of Germany and KenGen) were commissioned in late-2003. The World Bank has approved funding for a further 35 MW_e unit to be added to Olkaria II.

Kenyan geothermal power output was increased by 12 MW_e in 2000 when the first two stages of Kenya's first private geothermal plant were installed at Olkaria III. It was announced in January 2007 that the necessary regulatory approvals for an additional stage of Olkaria III (35 MW_e) had been made; construction was expected to begin during the first quarter of 2007 and completion was expected some 20 months later.

KenGen announced in December 2006 that the drilling of wells that would eventually lead to the construction of the 70 MW_e Olkaria IV plant would begin early in 2007.

The use of thermal waters for direct purposes is limited, although hot springs are being utilised by hotels to heat spas and there is some use of steam at Eburru for domestic purposes. The Government has proposed the creation of a company to specifically develop the country's geothermal resource, which in turn would encourage the development of direct uses.

To date there has been one successful instance of a commercial direct-use application. Oserian began as a 5 ha vegetable-growing farm in 1969. Today it has grown to be a 210 ha farm specialising in floriculture with an annual output of 380 million stems. The Geothermal Rose Project covers an area of 50 ha. The greenhouse heating system is powered by a 2 MW_e binary-cycle power plant commissioned in September 2004, making the company self-sufficient in electricity needs.

In forthcoming years it is expected that much exploration drilling will take place in the Suswa, Longonot and Menengai prospects, with the aim of helping Kenya to generate a greater proportion of its electricity from geothermal power.

Korea (Republic)

With its current heavy reliance on fossil fuels and nuclear power for electricity generation, Korea's energy supply structure may well develop into having a greater share of renewable energy in the coming years.

Historically, knowledge about and use of the country's geothermal potential has been relatively limited. As further research is undertaken it is not expected that a high-temperature resource suitable for power generation will be discovered. However, utilisation for direct purposes, mainly bathing, has existed for many hundreds of years.

The Korea Institute of Geoscience and Mineral Resources (KIGAM) is currently collecting data in respect of the low-temperature geothermal resource with a view to establishing a district heating scheme near the southeastern city of Pohang. The installation of geothermal heat pumps is at a very early stage of implementation but it is expected that this market will grow substantially.

Latvia

The utilisation of geothermal energy is getting under way in Latvia. The results of geological investigations have shown that there are geothermal anomalies in the central and southwestern parts of Latvia, where the temperature of rocks and underground water (at depths of 1 300-1 950 m) reaches 30-65^{o}C. Such low-temperature waters are suitable for the provision of heat and balneology. Furthermore, waters of 10-30^{o}C can be used for fish farming. It is also foreseen that heat pumps could be installed.

A geothermal database has been created with financial support from Denmark. Preliminary calculations have demonstrated that the use of thermal underground water resources (within the limits of geothermal anomalies - above 30^{o}C) could total 175 MW_t. However, the first experimental projects (to cover the base load of a centralised heat supply system) have shown that cost factors will prevent commercialisation of geothermal energy in the short term. There has also been some theoretical research on the use of geothermal energy in Latvian health resorts.

Lithuania

In the years following independence (1990), Lithuania has firstly been transforming its political system into a market economy and secondly moving away from its heavy reliance on fossil fuels and nuclear to a greater dependence on renewable energy. Membership of the European Union (2004) and national legislation passed in the first years of the 21st century are the main driving forces for this development.

Lithuania's geothermal resource, lying in the west of the country, has been found to be significant. In 2000 the 41 MW_t (18 MW geothermal heat and 23 MW heat from absorption heat pump driven boilers) Klaipeda Geothermal Demonstration Plant (KGDP) was commissioned and began producing 25% of the heat required by the city of Klaipeda.

Much work has been undertaken on the thermal waters in Vilkaviskis, a city in the southwestern part of the country, with a view to developing balneological uses and also a district heating scheme.

To date, Lithuania's extensive low-temperature resource has been harnessed for more than 200 ground-source heat pumps. A total of some 3 MW_t has been installed in the residential sector.

It is planned to increase the contribution of geothermal energy by developing new plants including possibly some for power generation.

Luxembourg

Luxembourg's low-temperature (<20^{o}C) geothermal resource is exploited for groundwater heat pumps in the residential sector. However, neither their production nor capacity is recorded.

FYR Macedonia

Research has shown that there are 18 geothermal fields in Macedonia, with more than 50 thermal springs, boreholes and wells with temperatures of 20-79^{o}C. The resource, utilised for spas, greenhouse heating and space heating before and during the 1980s, suffered a great setback during the collapse of the economy in the 1990s. Several projects failed completely and at the present time those that remain need financial support prior to the re-establishment of a viable geothermal industry. It is hoped that in the near term an atlas of Macedonia's geothermal potential can be compiled and a strategy for the country's geothermal usage be formulated.

Mexico

Reflecting the country's location in a tectonically active region, geothermal manifestations are particularly prevalent in the Mexican Volcanic Belt (MVB), as well as in the states of Baja California and Baja California Sur. Development has, in the main, been concentrated on electric power production, although there is a small amount of geothermal power used for direct purposes.

At the present time the country has four operational fields, with a total installed capacity of 953 MW_e: Cerro Prieto (northern Baja California), 720 MW_e (13 condensing units, ranging from 25 MW_e to 110 MW_e); Los Azufres (MVB, 250 km west of Mexico City), 188 MW_e (14 condensing, back-pressure and binary units, ranging from 1.5 MW_e to 50 MW_e); Los Humeros (MVB), 35 MW_e (7 x 5 MW_e back-pressure units) and Las Tres Virgenes (northern Baja California Sur), 10 MW_e (2 x 5 MW_e condensing units).

It has been estimated that there is a potential of 500 MW_e for additional power generation from extensions to the four existing fields and development of new zones. Planned projects include construction and installation of about 200 MW_e in the present fields of Cerro Prieto, Los Azufres and Los Humeros and the Cerritos Colorados project in a fifth field - La Primavera (MVB).

Geothermal heat used directly is predominantly utilised for bathing and swimming. The reported 156 MW_t installed capacity is widely distributed throughout the country. Minimal amounts of direct heat are utilised for space heating, greenhouse heating, agricultural drying and mushroom breeding. Geothermal heat pumps are virtually unknown.

Mongolia

To date, very little comprehensive research has been undertaken on Mongolia's geothermal potential. However, with a view to diversifying electricity generation (presently mostly fossil-fuel based), especially for isolated rural communities, the Government may develop a greater use of renewable energy.

Regional studies have identified five areas with resource potential, while the country's hot springs have been used directly for heating, bathing and balneology for many years. There is scope for the resource to be utilised further in district heating schemes, industrial processing and agricultural applications (greenhouse heating, cashmere and wool washing/drying).

A study of the Shargaljuut hot springs (west-central Mongolia) suggests that the area would be suitable for small-scale power generation.

Nepal

With the country's high availability of, and reliance on, hydropower for electricity generation, there has not historically been an incentive to develop any other forms of supply. However, for reasons of climatic change, political and financial problems, there needs to be a diversification of energy sources in the future. To this end, the Government has incorporated a review of Nepal's geothermal potential within the Alternative Energy Perspective Plan (2007-2017).

Most of the 30 geothermally active areas are located in the remote northern regions and the low-temperature resource is unlikely to be utilised for power generation in the near term. A more likely use is for development of direct use for bathing purposes (currently approximately 2 MW_t). This would have the effect of popularising the technology and thereby providing revenue for further research.

Netherlands

Whilst the Netherlands has a similar geological situation to neighbouring countries, its geothermal potential (estimated by the Netherlands Institute of Applied Science to be a theoretical 90 000 PJ) has not been utilised to anywhere near the same extent. The country has access to indigenous low-cost natural gas and other forms of renewable energy that have resulted in a general lack of long-term support and publicity for geothermal power, unlike for example, Germany.

The Dutch Agency for Energy and Environment (NOVEM) initiated the Platform for Geothermal Energy in 2002. It is expected that this will result in study of the country's deep-layer geothermal heat – a resource that to date has not been utilised for heating or electricity generation.

Heat pumps using vertical borehole heat exchangers have been and continue to be installed in private houses and small commercial buildings: some 1 100 were in place at end-2004. Groundwater heat pumps are also used on a small scale, again mainly in small commercial buildings. However there is a significant market for medium to large-scale heat pumps combined with groundwater wells. Most of the 300 systems in operation at end-2004 were installed in commercial buildings, industrial zones and housing developments to provide district heating and cooling schemes.

New Zealand

New Zealand is exceptionally rich in geothermal fields, as well as in a large number of other geothermal features. Temperatures range from 70°C to greater than 220°C in the 129 identified areas. Substantial capacity exists for both the generation of geothermally produced power and also for geothermal heat used directly. However, in common with many countries today, New Zealand is experiencing the effects of privatisation of its electricity industry, together with inter-fuel competition for generation, environmental concerns and the effects of climate change. These factors have all helped to slow the pace of geothermal development in recent years.

The first geothermal power plant came into operation at Wairakei, north of Lake Taupo (North Island) in November 1958. It has generated electricity for nearly 50 years and today its capacity stands at 162 MW_e. Wairakei was the second geothermal power station to be built in the world and the first to tap a hot pressurised water resource. An additional 14 MW_e binary capacity became operational in September 2005.

By end-2005 some 263 MW_e of additional geothermal capacity had come on line, in the central North Island's Taupo Volcanic Zone (TVZ). Included in this total is the 39 MW_e binary-cycle extension at the Mokai plant, which was the first geothermal development to be owned by a Maori Trust.

One further plant (10 MW_e) began operating in 1998 in the locality of Northland – in the far north of North Island.

At end-2005 installed capacity for direct heat uses stood at about 350 MW_t. The main user of direct heat is at Kawerau, where a 210 MW_t plant generates clean process steam for various procedures within a pulp and paper mill operation. Geothermal steam at other locations is also used for agricultural drying (10% of direct-heat capacity in 2004), bathing and swimming (9%), space heating (7%) and fish and animal farming (6%).

Geothermal heat pumps are virtually unknown in New Zealand, with only isolated installations in South Island.

Nicaragua

Nicaragua is the Central American country with the greatest geothermal potential, in the order of several thousand megawatts. Reserves that can be estimated with a higher degree of confidence total about 1 100 MW_e. Medium- and high-temperature resources are associated with volcanoes of the Nicaraguan Depression, which parallels the Pacific Coast.

Geothermal exploration began at the end of the 1960s, focussing on the Momotombo and San Jacinto-Tizate geothermal fields. Studies increased after 1973, at a time when the oil crisis had a large impact on Nicaragua's economy. Geothermal electricity production started at Momotombo in 1983.

Exploitation of geothermal power in the Momotombo area, located at the foot of the volcano of the same name, began when the first 35 MW_e single-flash unit was commissioned in 1983. A second 35 MW_e unit was added in 1989. Gross output of electricity reached a peak of 468 GWh in 1992 but subsequently fell away to a low of 102 GWh in 1999 owing to over-exploitation of the field and lack of re-injection.

In 1999, ORMAT secured a 15-year contract to improve electricity output at Momotombo. Since then, the company has drilled four deep wells (OM-51 to OM-54), and of these, only OM-53 was a good producer (9-11 MW). A number of wells have been cleaned of scale and chemical inhibition systems installed. About 80% of waste geothermal fluids are being injected back to the reservoir and a new reservoir management plan has been implemented. Since May 2002, these efforts have increased and stabilised the electrical output of the flash plant at about 29 MW_e. In November 2002, a 7.5 MW_e binary energy converter came online, raising total generation capacity at Momotombo to 77.5 MW_e. The field now has 12 production wells, and four injection wells.

The San Jacinto-Tizate field was granted an exploitation licence in 2003. The project proposed consists of a plant of 20 MW_e combined-cycle technology (Phase I) followed by a 46 MW_e expansion using condensing turbine generation (Phase II). At the start of 2007, 2 x 5 MW_e back-pressure units were operational (Stage 1 of Phase I). An additional 10 MW_e will represent Stage 2 of Phase I and subsequently Phase II will add 46 MW_e, bringing the total installed capacity to 66 MW_e.

Nicaragua's total geothermal electricity output has been on a rising trend since 1999 and in 2006 totalled 310.8 GWh.

Norway

Norway's total reliance on indigenous hydropower resources for its electricity supply has meant that historically, no other energy resource was utilised. In 1999 a 2 MW_e HDR pilot plant was planned for Oslo but the project was abandoned. Heat pump installations are extremely common in Norway, albeit the majority are air-source. However, it has been stated that the market will develop in favour of ground-source heat pumps.

Papua New Guinea

Positioned as it is in the same tectonic region as Indonesia and the Philippines, exploration has been undertaken to establish the geothermal potential of Papua New Guinea. To date, 27 wells have been drilled and since 2002 activity has focussed on the island of Lihir, off the northeast coast. In June 2002 a 6 MW_e back-pressure unit was approved by Lihir Gold Ltd, the owner of the island's gold mine, one of the largest in the world. Commissioning of the plant came just 10 months later and provided the mine with 10% of its power needs.

At end-July 2005 the plant was expanded with the addition of a 30 MW_e unit. A further 20 MW_e are due for installation before end-March 2007. At 56 MW_e the plant will satisfy current electricity demand. However, the company announced during fourth quarter 2006 that an expansion to the gold-processing facility had been approved. In order to meet the subsequent increased power demand in 2010, funding for further geothermal exploration drilling had also been approved.The power from the Lihir Gold plant not only provides electricity to the mine and associated buildings but also to housing and local villages.

Philippines

The Philippines archipelago is exceptionally well-endowed with geothermal resources. Today the country is the world's second largest user of geothermal energy for power generation. With only some 46% of the stated geothermal potential of 4 340 MW harnessed, there is much room for growth. The Government plans to double the current installed capacity from renewable energy in the next decade (the so-called '100 in 10' target) and the geothermal sector will undoubtedly benefit.

As recently as 2000, geothermal energy was contributing about 25% of national electricity generation. However, the supply of indigenous gas has become significant, so that by 2005 the share of geothermal stood at approximately 18%. At end-2005 eleven power plants in six fields were operating with a total installed capacity of 1 978 MW_e. The fields, spread throughout the islands, are at Mak-Ban (Luzon), Tiwi (Luzon), Tongonan (Leyte), Palinpinon (Negros), Bac-Man (Luzon) and Mindanao (Mindanao). Four of the steam-fields are operated by PNOC-Energy Development Corporation, whilst the remaining two are operated by Chevron Geothermal Philippines Holding Inc. (CGPHI). PNOC-EDC's first vertically-integrated operation (49 MW_e) was commissioned at the beginning of February 2007. For the period 2006-2014, the Department of Energy lists two 'committed' projects and 20 'indicative' projects, with a total capacity of 824 MW.

Direct use of geothermal heat is currently at the very low level of 3.3 MW_t of which 1.6 MW_t is used for agricultural drying and 1.7 MW_t for bathing and swimming. The Government plans to further develop direct utilisation.

Poland

Poland has substantial resources of geothermal energy, but not at high temperatures. The available resource ranges from reservoir temperatures of 30°C to 130°C at depths of 1 to 4 km.

Although thermal water has been used for balneological purposes for many centuries, development of geothermal power for heating has only taken place during the past 15 years or so. Both the Strategy of Renewable Energy Resources Development which came into effect in 2000 and Polish membership of the European Union in 2004 have helped to encourage the growth of renewable energy use in general, but greater promotion of geothermal energy is needed.

Three heating plants were installed in the period 1992-1999 in the Podhale region (near Zakopane), in Pyrzyce (near Szczecin) and in Mszczonów (near Skierniewice). Two further heating plants came into operation in 2001 (Uniejow) and 2002 (Slomniki). Some of the geothermal units work in conjunction with heat pumps and/or fossil-fuelled boilers.

Geothermal water is mainly used for heating purposes. The bulk of the capacity installed for direct heating is utilised for district heating, with much smaller amounts for bathing and swimming, greenhouse heating, fish farming and wood drying. The number of ground-source heat pumps has grown steadily and capacity now stands at about 53 MW_t.

At the present time it is not foreseen that geothermal heat will be utilised for traditional electricity generation. However, there is an interest in studying binary plants which would be based on 90+^{o}C water.

Portugal

The limited geothermal resources in mainland Portugal have been developed for direct use, whereas geothermal occurrences in the Azores are utilised for the production of electricity as well as being used directly.

Twelve areas with potential for developing geothermal electricity generation have been identified on the islands of Faial, Pico, Graciosa, Terceira and São Miguel in the Azores. Two plants are in operation on São Miguel: Pico Vermelho, a 3 MW_e back-pressure steam turbine integrated in a single-flash system and Ribeira Grande with 2 x 2.5 MW_e + 2 x 4 MW_e ORMAT dual turbo-generators. The 3 MW_e unit at Pico Vermelho is due to be replaced, with a new units with a capacity of up to 10 MW_e.

Research has shown that the island of Terceira has a high-temperature resource suitable for power generation. Construction of a 12 MW_e plant is planned for 2009. Output will then meet approximately 50% of local electricity demand.

Low-enthalpy occurrences are spread throughout the mainland and have been harnessed for small district heating schemes, greenhouse heating and bathing and swimming (including balneology). Direct use in the Azores excludes district heating. To date there has been little interest in geothermal heat pumps. At end-2004, total installed capacity stood at 30.35 MW_t of which 27.09 MW_t was for bathing and swimming, 1.79 MW_t for greenhouse heating and 1.47 MW_t for district heating.

Romania

Romania's low-enthalpy geothermal potential lies mainly along the western border with Hungary and in the south-central part of the country. Usage of the country's springs has been known since Roman times but it was only during the 1960s that energy-directed exploration began. To date some 230 exploration wells have been drilled, of which 76 have become production wells and six have become injection wells.

The transition to a market economy, together with the run-up to membership of the European Union, have certainly assisted with the development of geothermal energy in Romania but for the full potential of the resource to be realised, access to adequate funding and the latest technology is required.

Currently geothermal heat is used only for direct purposes - there is no use for electricity generation or heat pumps. District heating output represents about 43%; bathing and swimming (including balneology) 28%; greenhouse heating 17%; industrial process heat 9% and fish farming 2%.

Russian Federation

Russia has a significant geothermal resource. Thermal waters of 100–120°C have been identified in several areas of the Federation: Kaliningrad, the Northern Caucasus (Alpine and Platform provinces), Western Siberia, Lake Baikal, the Russian Far East, Sakhalin, Chutotka and, most significantly, in Kamchatka and the Kuril Islands where the thermal water reaches 300°C. It has been estimated that the high-temperature resources defined to date in the Kamchatka Peninsula could ultimately support generation of 2 000 MW_e.

The country's energy sector has long been based on fossil fuels and the exploitation of hydroelectric and nuclear power, and the contribution from geothermal energy represents less than 1%. Considering the Federation's vast area and also the logistics of fuel transportation, the use of geothermal heat for power generation could be particularly important in the northern and eastern regions. However, the main thrust of Russian geothermal utilisation has been, and continues to be, for direct purposes.

The first plant using geothermal energy for power generation in Kamchatka was commissioned at Pauzhetka in 1966. It was a 5 MW_e single-flash unit which was enlarged to 11 MW_e in 1980; in 1998 a 4 MW_e plant was commissioned at Mutnovsky, followed in 1999 by an additional 8 MW_e – all single-flash units. 2002 saw the commissioning of a 50 MW_e plant at Verkhne Mutnovsky. The islands of Kunashir and Iturup in the Kuril group have small units of 2.6 MW_e and 3.4 MW_e. In 2005, total installed capacity thus stood at 79 MW_e.

It has been reported that development is under way for a 6.5 MW_e binary unit at Verkhne

Mutnovsky, a 100 MW_e unit at Mutnovsky, a 50 MW_e unit in the Kaliningrad region and a 4 MW_e unit in the Stavropol region.

The end-2005 estimate for total installed capacity for direct use amounted to more than 307 MW_t (excluding heat pumps, known to exist in the Kamchatka region), of which 52% was used for greenhouse heating, 36% for heat supply, 8% for industrial processes and 1% each for cattle and fish farming, drying of agricultural products, and swimming pools and baths.

There is much scope for the installation of heat pumps in Russia, but their use is presently at an early stage of development.

Saudi Arabia

Exploration for geothermal resources in Saudi Arabia began in 1980. It was established that 10 hot springs with temperatures ranging from 50°C to 120°C exist in the southern part of the country and the volcanic areas of the west.

Saudi Arabia has access to energy not only in the form of indigenous oil and natural gas but also to a large solar and wind resource. Despite a burgeoning demand for electricity generation, to date no use has been made of the country's geothermal heat. It is believed that in future this available heat could be developed for power generation, but it is expected that solar and wind power will take precedence.

Serbia

Exploration for geothermal resources in Serbia began in 1974: four provinces were discovered and preliminary drilling and pilot studies ensued. At the present time the main utilisation is at the 59 established thermal spas for balneology and recreation. Of an installed capacity of 83 MW_t, 43% is used for bathing and swimming, 24% for space heating, 19% for greenhouses, 8% for fish and other animal farming, 5% for industrial process heat and 1% for agricultural drying. In addition, about 6 MW_t of thermal water heat pumps are in use.

It has been established that Serbia's geothermal resource is suitable both for power generation in the future and also for expansion of the heat pump market.

Slovakia

Slovakia's geothermal resources, first explored during the 1970s, have been located in 26 areas covering 27% of the territory. The country has thermal waters ranging from low temperature (20-100°C) to medium temperature (100-150°C) to high temperature (>150°C). At the present time, utilisation is only for direct purposes; out of an installed capacity of 186 MW_t in 2005, 64% was used for bathing and swimming, 17% for district heating, 17% for greenhouse heating and 2% for fish farming. Another 1.4 MW_t represented eight geothermal heat pumps.

Amongst other projects, it has been reported that a large district heating scheme is being considered for Slovakia's second city, Košice.

Slovenia

Slovenia has mostly low-enthalpy geothermal resources, with only one area in the northeast of the country possessing a high-enthalpy resource. To date, the latter has not been utilised and the former is used at 27 locations for direct purposes only. Bathing and swimming (including balneology) is the most significant use at 39% (out of an installed capacity of 44.7 MW_t), followed by individual space heating 36%, greenhouse heating 18%, air conditioning (cooling) 3%, district heating 2% and industrial process heat 2%. It has been estimated that there is 1.6 MW_t capacity of heat pumps used for raising the temperature of swimming pool water and also some 300 ground-source heat pumps totalling 3.3 MW_t.

Spain

Research has shown that a low-enthalpy geothermal resource is widely distributed across the Spanish mainland. The main areas are in the northeast (Barcelona, Gerona and Tarragona), southeast (Granada, Almeria and Murcia), northwest (Orense, Pontevadra and Lugo) and the centre (Madrid). Other minor areas also exist. In the Canary Islands, it has been found that a high-temperature resource exists on Tenerife (but is not commercially viable) and that Lanzarote and La Palma have an HDR resource.

In 2005 it was reported that the small amount of capacity installed for direct purposes (22.3 MW_t) was divided amongst individual space heating (4.8 MW_t), greenhouse heating (14.9 MW_t) and swimming and bathing (2.6 MW_t).

Sweden

Sweden's utilisation of geothermal heat is on a very limited scale. Lund, in the far south of Sweden, has had a 4 MW_t geothermal heat pump providing base-load heat to a district heating network for the past 20 years. A venture at the Lund scheme, the Deep Geothermal Project, plans to utilise deep water with a temperature greater than 100°C for direct heat application in the existing plant. Another project in Malmö, also in the far south, plans to extract geothermal heat by means of an absorption heat pump.

There are many small ground-source heat pumps installed in the country. It has been estimated that by 2005 some 275 000 (average size, 12 kW) had been installed in residential buildings. Some 600 larger pumps (average size, 900 kW) have been installed in district heating schemes.

Switzerland

Switzerland's installed capacity for utilising geothermal energy has grown rapidly in recent years and the country now ranks among the world leaders in direct-use applications (there is no geothermal-based electricity). There are two main components to Switzerland's geothermal energy: the utilisation of shallow resources by the use of horizontal coils, borehole heat exchangers (BHE), foundation piles and groundwater wells, and the utilisation of deep resources by the use of deep BHEs, aquifers by singlet or doublet systems, and tunnel waters. In virtually all instances heat pumps are the key components.

In 2005 there were over 35 000 ground-source heat pumps installed throughout the country, representing about 532.4 MW_t. The remaining 49.2 MW_t of capacity was utilised for bathing and swimming (40.8 MW_t), district heating (6.1 MW_t), air conditioning (2.2 MW_t) and snow melting (0.1 MW_t).

Research had shown that the area of Basle in northern Switzerland had the required criteria (a temperature of 200^{o}C at about 5 km depth and an existing large heat distribution system) for the development of Deep Heat Mining (DHM) to proceed. The project began in 1996 and progressed through the stages of site selection and preparation. During 2003-2006 drilling of the first well took place (reservoir definition) followed by the drilling of the 2nd and 3rd wells for production tests. Further testing will take place during 2007–2008, during which time the pilot plant will be designed. It is intended that the plant will be built and for operations to begin in the period 2009-2010. DHM research has also been conducted in the Geneva canton and a site selected for further studies.

There remains substantial room for growth in Switzerland's geothermal sector. The annual growth-rate for heat pumps is estimated at 15% and the Government is actively supporting research and development into geothermal energy.

Taiwan, China

Taiwan lies on major geological fault-lines along the Pacific Rim, and has abundant geothermal resources. A comprehensive exploration effort has indicated a total potential of up to 1 000 MW. However, most of the resources are located in remote areas or protected lands and that makes them difficult to develop. The Government has set a target of 50 MW for 2010. Currently, a BOT project at Chin-Suei, I-Lan County is under development and is aimed at the integration of geothermal energy usage with recreational facilities. It is planned to construct a 5 MW plant by 2008.

Tanzania

Preliminary studies conducted in different parts of Tanzania by surface geological exploration, magnetic and gravity data analyses and reconnaissance exploration have indicated that the country possesses high-temperature (exceeding 200^{o}C) fluids beneath the volcanoes.

The presence of hot springs has provided a positive indication of the country’s geothermal potential. Fifty hot springs have been sampled, with the majority having a surface temperature of 86^{o}C and a reservoir temperature of 220-276^{o}C.

Presently the country’s geothermal resource is not utilised. However, and especially in the light of an increasing energy requirement, the National Energy Policy 2003 highlights the need to assess the potential and establish its viability.

Thailand

Investigations of geothermal features in Thailand began in 1946 and subsequently more than 90 hot springs located throughout the country were mapped. However, it was not until 1979 that systematic studies of the resources began.

A small (0.3 MW_e) binary-cycle power plant was installed at Fang, in the far north near the border with Myanmar. Since commissioning in December 1989, this sole Thai geothermal plant has operated successfully, with an 85-90% availability factor. In addition, the Electricity Generating Authority of Thailand (EGAT) is using the 80^{o}C exhaust from the power plant to demonstrate direct heat uses to the local population. The exhaust can be used for crop drying and air conditioning (the latter not currently in use). A further example of utilising the heat directly is a public bathing pond and sauna that have been constructed by the Mae Fang National Park.

Geothermal systems at San Kampaeng, Pai and nine other locations are reported to be under further investigation, but to date Thailand's national programme on geothermal energy has still not been firmly established and no other developments have occurred.

Turkey

A significant factor in Turkey's high geothermal potential is the fact that the country lies in the Alpine-Himalayan orogenic belt. Geothermal exploration began during the 1960s, since when about 170 fields have been identified. Although some of these are high-enthalpy fields, 95% are low-medium enthalpy resources and thus more suited to direct-use applications.

At end-2005, installed direct-use capacity totalled 1 229 MW_t, of which 635 MW_t provided the space heating and thermal facilities of 103 000 residence-equivalents, 192 MW_t provided heating for 63.5 ha of greenhouses and 402 MW_t was utilised for bathing and swimming (215 spas).

Following research undertaken in 1968 into using geothermal resources for the production of electricity, a 0.5 MW_e pilot plant was installed in 1974 in the Kizildere field (near Denizli in south-western Turkey). In 1984 the 20 MW_e single-flash Kizildere geothermal power plant came into operation. In addition to electricity generation, the plant has an integrated liquid CO_2 and dry ice production factory that utilises the geothermal fluids.

Various geothermal fields with power generation potential have been discovered and are either undergoing study (Denisli-Sarayköy, 6 MW_e; Çanakkale-Tuzla, 7.5 MW_e and Kütahya-Simav, 10 MW_e) or are under construction (Aydin-Germencik, 25 MW_e and Aydin-Salavath, 8 MW_e).

Uganda

Uganda’s power sector relies heavily on indigenous hydroelectricity. The country is particularly well-endowed with a hydro resource but large losses due to long transmission lines, together with the possible effects of climate change on the supply of water, has ensured that the Government recognises the importance of diversification.

Research has established that three areas in particular, lying in the west of the country near the border with the Democratic Republic of Congo, have considerable geothermal potential. Assessments are being made of two prospects: Katwe and Kibiro. The former has been shown to have a temperature of 160-200°C and the latter in excess of 200°C. A pre-feasibility study is being conducted in the area of Buranga. It is hoped that in future these areas will enable electricity generation from small-scale geothermal plants in rural areas.

Ukraine

Research has shown that the country possesses four large artesian basins with significant resources of thermal and superheated waters. This geothermal resource allowed Ukraine to construct nine plants between 1978 and 2002, utilising the heat directly for individual space heating and district heating. Two of the plants are located in Yantarnoye (Krasnogvardeysky region) and Medvedevka (Dzhankoy region). The former with an installed capacity of 3 MW_t was operating until 2003 and is now undergoing modernisation; the latter is still in operation.

United Kingdom

There is no recorded high-temperature resource in the UK and although the country possesses a low- and medium-enthalpy resource it is, unlike some of its European neighbours, very under-utilised. Research into HDR technology has ceased.

There has been no direct Government support for geothermal energy despite the country being required to produce 10% of electricity generation from renewable energy by 2010. The only application of low-enthalpy geothermal energy has been a large-scale scheme to supply combined heat and power to 3 000 homes, 10 schools and numerous commercial buildings in the city of Southampton.

There are only isolated instances (estimated at 550 at end-2004) of ground-source heat pumps in existence, representing about 10 MW_t. The Low Carbon Buildings Programme (LCBP) was introduced in April 2006 (replacing The Clear Skies Project) to provide grants for a range of renewable technologies including ground-source heat pumps. It is hoped that this will stimulate the market.

The UK has many disused mines and at the present time there are two projects in Glasgow using water that has accumulated in the mines and then pumped via heat exchangers to heat apartment blocks. Several other schemes are under consideration.

An ambitious plan to regenerate the site of a cement works which closed in 2002 will hopefully lead to a renewable energy village in Upper Weardale, County Durham. The area, which was formerly mined for lead and fluorspar, is known to possess a source of geothermally-heated water (46°C at a depth of 1 000 m). The Weardale Task Force's Master Plan for the eco-friendly village envisages that the heat will be utilised for a public hot-springs spa and fish-breeding ponds. Additionally, the development will include environmentally-friendly commercial and residential property and a range of tourist and leisure activities based on the use of biomass (for a district heating scheme), wind, solar and hydro technologies.

Following the viability studies currently being conducted, it is expected that a planning application for the village will be submitted in early autumn 2007.

United States of America

The USA possesses a huge geothermal resource, estimated at some 50 000 MW_e, located largely in the western half of the country. Research has shown that geothermal energy has been used in North America for many thousands of years but the first documented commercial use was in 1830 in Arkansas. In 1922 an experimental plant began generating electricity in California but, proving to be uneconomic, it soon fell into disuse. Another 38 years were to pass before the first large-scale power plant began operations at The Geysers, north of San Francisco, California. The USA is the world's largest producer of electricity generated from geothermal energy.

Only California, Nevada, Hawaii and Utah utilise geothermal energy for power generation; investigative studies undertaken in Oregon during the early 1990s proved to be unsuccessful. However, the 1990s saw dramatic change in the geothermal power industry: plants came on line, plants were retired, there were changes of ownership (resulting, in some cases, in operational efficiencies), etc. By end-2005 total effective capacity stood at 2 564 MW_e. It is reported that 88 MW_e of capacity is under construction and planned projects would add 213 MW_e capacity.

Geothermal heat suitable for direct utilisation is far more widespread through the US, ranging from New York State in the east to Alaska in the west. At end-2004, a total of 617 MW_t installed capacity was used for fish and animal farming (138 MW_t), greenhouse heating (97 MW_t), bathing and swimming (112 MW_t), district heating (84 MW_t), space heating (146 MW_t), agricultural drying (36 MW_t), industrial process heat (2 MW_t), and snow melting (2 MW_t).

In addition, it is estimated that between 600 000 and 800 000 heat pumps are installed in the US (in all 50 states but more commonly in the mid-west, mid-Atlantic and southern states).

The US Department of Energy continues to support geothermal energy through sharing the cost of R&D with industry, funding state programmes and providing technical assistance to small developers (through GeoPowering the West Program).

Vietnam

The government-supported exploration and evaluation of the country's geothermal resource has shown that there is a total of 269 prospects and a potential of 649 MW_t. The south-central, north-western and north-central regions are the areas of Vietnam with the greatest potential.

At the present time there is no geothermal power generation: a pre-feasibility report for 6 plants (total capacity, 112.7 MW_e) in central Vietnam has been prepared but the project has been postponed.

Direct utilisation is limited to the provision of industrial process heat (iodide salt production, 1.4 MW_t) and bathing and swimming (29.7 MW_t).

Zambia

Zambia's wealth of available electricity generation from hydro power has resulted in a lack of progress in the development of other renewable energies. Although Government policy supports the use of renewables in general there is no specific policy for geothermal energy in particular. The country exports electricity surplus to its requirements and despite Government policy to raise the rate of access in both urban and rural areas, it is infeasible for rural areas to be supplied from the grid. To this end, a Rural Electrification Authority (REA) to administer Rural Electrification Projects (REPs) was established in 1994, with a view to the installation of mini-grids and/or stand-alone systems.

Exploration has shown that Zambia possesses in excess of 80 hot springs and that electricity generation could be possible by means of binary-cycle units. Two projects, at Kapisya and Chinyunyu, were formulated during the 1980s and although two Organic Rankine Cycle (ORC) turbogenerators (280 kW) were installed at the former (for rural electrification), it never became operational owing to insufficiently high resource temperatures. The plan for the Chinyunyu hot springs was to build a health resort and provide electricity for the local community. A lack of funding precluded this project from proceeding.

12. Wind Energy

COMMENTARY

Resource and Potential

Winds are generated by complex mechanisms involving the rotation of the earth, heat energy from the sun, the cooling effects of the oceans and polar ice caps, temperature gradients between land and sea and the physical effects of mountains and other obstacles. Some of the windiest regions are to be found in the coastal regions of the Americas, Europe, Asia and Australasia. Most mountain regions are also windy, while the interiors of large land masses are generally less so. The total resource is vast; one estimate suggests around a million gigawatts (Cole, 1992) 'for total land coverage'. If only 1% of the area was utilised, and allowance made for the lower load factors of wind plant (15-40%, compared with 75-85% for thermal plant), the wind-power potential would still correspond, roughly, to the total worldwide capacity of all electricity-generating plant. The offshore wind resource is also huge, with European resources, for example, capable of supplying all the European Union's electricity needs, without going further than 30 km offshore.

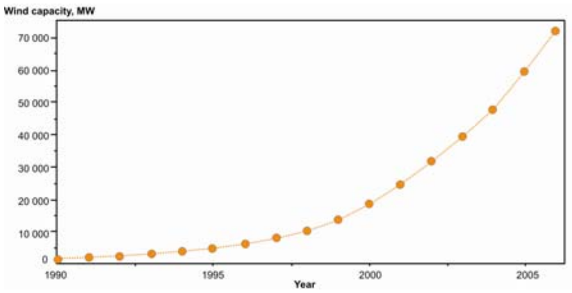
The locations of the 'best' onshore wind resources, based on maps by Czisch (2001), are summarised in Fig. 12-1, which shows that wind energy resources are well distributed.

The progress and prospects for wind energy may be assessed by examining the projections for 2010 as set out in the European

Figure 12-1 Summary of locations of the most attractive regions for wind energy
Source: Czisch, 2001

Region	Location
Europe	North and west coasts, some Mediterranean regions
Asia	East coast, some inland areas
Africa	North, southwest coast
Australasia	West and south coast
North America	Most coastal regions, some central zones, especially where mountainous
South America	Best towards the south

Figure 12-2 Growth of world wind capacity
Source: Milborrow and 'Windpower Monthly'



Commission's White Paper on renewable energy (EC, 1997). Wind was set a European target of 40 GW by 2010, 16 times the capacity in 1995, but the target was realised by 2005. The only other renewable energy to achieve its goal by 2005 was large-scale hydro – which was set a much more modest growth target (a 10% increase over 1995).

World wind energy capacity has been doubling about every three and a half years since 1990, as shown in Fig. 12-2. It is doubtful whether any other energy technology is growing, or has grown, at such a rate. Total world wind capacity at the end of 2006 was around 72 000 MW and generation from wind was around 160 TWh, which roughly equates to the annual consumption of electricity in Sweden. Germany, with over 20 000 MW, has the highest capacity, but Denmark, with over 3 000 MW, has the highest level per capita and wind power accounts for about 20% of Danish electricity consumption.

Wind energy is being developed in the industrialised world for environmental reasons and it has attractions in the developing world as it can be installed quickly in areas where electricity is urgently needed. In many instances it may be a cost-effective solution if fossil fuel sources are not readily available. In addition there are many applications for wind energy in remote regions, worldwide, either for supplementing diesel power (which tends to be expensive) or for supplying farms, homes and other installations on an individual basis.

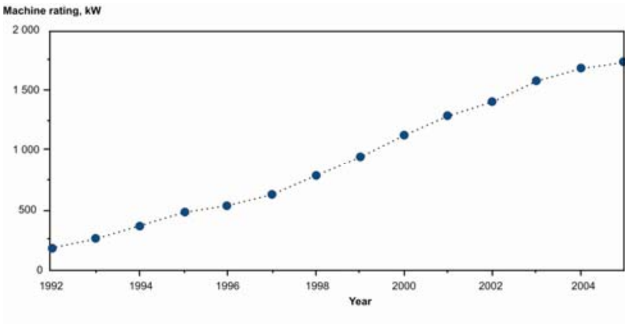
Most world wind capacity is located at onshore sites, but offshore wind farms have been completed, or are planned, in Denmark, Ireland, Sweden, Germany, the United Kingdom and elsewhere. Offshore wind is attractive in locations such as Denmark and the Netherlands where pressure on land is acute and windy hill-top sites are not available. In these areas offshore winds may be 0.5 to 1 m/s higher than onshore, depending on the distance. The higher wind speeds do not usually compensate for the higher construction costs, but the chief attractions of offshore are that it is a large resource with a low environmental impact.

Types of Modern Wind Turbine

Early machines – twenty-five years ago - were fairly small (50-100 kW, 15-20 m diameter) but there has been a steady growth in size and output power. Several commercial types of wind turbine now have ratings of over 2 MW and diameters of around 60-70 m; machines for the offshore market have outputs of up to 5 MW and diameters up to 110 m. The way in which sizes have increased is shown in Fig. 12-3; the average rating of turbines installed in Germany in 1992 was 180 kW and in 2005 it was 1 728 kW – nearly ten times as much.

Machine sizes have increased for two reasons. Larger machines are cheaper and they deliver more energy. The energy yield is improved partly because the rotor is located higher from the ground and so intercepts higher-velocity winds, and partly because they are slightly more efficient. Yields, in kWh per square metre of

Figure 12-3 Average size of wind turbines installed in Germany, 1992-2005
Source: German Wind Energy Institute (DEWI)



Wind energy is being developed in the industrialised world for environmental reasons and it has attractions in the developing world as it can be installed quickly in areas where electricity is urgently needed.

rotor area, are now double those of 1990 (Welke and Nick-Leptin, 2006). Reliability has also improved steadily and most wind turbine manufacturers now guarantee availabilities of 95%.

The majority of the world's wind turbines have three glass-reinforced plastic blades. The power train includes a low-speed shaft, a step-up gearbox and an induction generator, either four or six-pole. There are numerous other possibilities, however. Wood-epoxy is an alternative blade material and some machines have two blades. Variable-speed machines are becoming more common and many generate power using an AC/DC/AC system, but double-fed induction generators are becoming increasingly common. Variable speed brings several advantages - it means that the rotor turns more slowly in low winds (keeping noise levels down), it reduces the loadings on the rotor and the power conversion system, and the generators are usually able to deliver current at any specified power factor. Some manufacturers build direct-drive machines, without a gearbox. These are usually of the variable-speed type, with power-conditioning equipment.

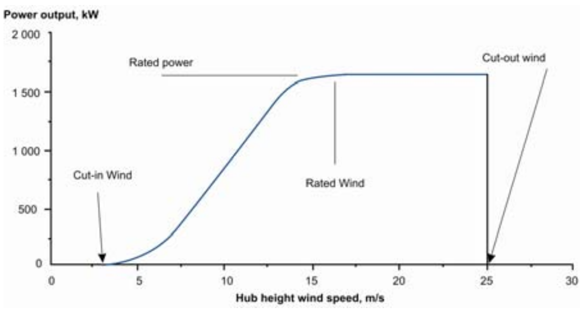
Towers are usually made of steel and the great majority are of the tubular type. Lattice towers, common in the early days, are now rare, except for very small machines in the range 100 kW and below. Recent increases in the price of steel have re-awakened interest in concrete towers, but there are relatively few examples yet.

As the power in the wind increases with the cube of the wind speed, all wind turbines need to limit their power output in very high winds. There are two principal means of accomplishing this, with pitch control on the blades or with fixed, stall-controlled blades. Pitch-controlled blades are rotated as wind speeds increase so as to limit the power output and once the ‘rated power’ is reached, a reasonably steady output can be achieved, subject to the control system response. Stall-controlled rotors have fixed blades which gradually stall as the wind speed increases, thus limiting the power by passive means. These dispense with the necessity for a pitch-control mechanism, but it is rarely possible to achieve constant power as wind speeds rise. Once peak output is reached the power tends to fall off with increasing wind speed, and so the energy capture may be less than that of a pitch-controlled machine. The merits of the two designs are finely balanced and until recently roughly equal numbers of each type were being built. Since the turn of the century, however, pitch-controlled machines have become more popular.

Energy Production

Contrary to popular opinion, energy yields do not increase with the cube of the wind speed, mainly because energy is discarded once the rated wind speed is reached. It does not make economic sense to build turbines with very high ratings that will only be reached on rare occasions. To illustrate the key parameters and the concept of rated output, a typical power curve for a 1.65 MW machine, 63 m in diameter, is shown in Fig. 12-4. Most machines start to generate at a similar speed - around 3 to 5 m/s –

Figure 12-4 Power curve and key concepts for a 1.65 MW wind turbine
Sources: Milborrow, based on data from Vestas Wind Systems A/S for a 66m wind turbine



As wind energy is not generally cost-competitive with the thermal sources of electricity generation, the pattern of development has been largely dependent on the support mechanisms provided by national governments.

and shut down in very high winds, generally around 20 to 25 m/s.

Annual energy production from the turbine whose performance is charted in Fig. 12-4 is around 1 500 MWh at a site where the wind speed at 60 m height is 5 m/s, 3 700 MWh at 7 m/s and 4 800 MWh at 8 m/s. Wind speeds around 5 m/s can typically be found away from the coastal zones in all five continents, but developers generally aim to find higher wind speeds. Levels of around 7 m/s are to be found in many coastal regions and over much of Denmark; higher levels are to be found on many of the Greek Islands, in the Californian passes - the scene of many early wind developments - and on upland and coastal sites in the Caribbean, Ireland, Sweden, the United Kingdom, Spain, New Zealand and Antarctica. Offshore wind speeds are generally higher than those onshore – around 8 m/s in European coastal waters, for example.

Wind Energy Costs

As wind energy is not generally cost-competitive with the thermal sources of electricity generation, the pattern of development has been largely dependent on the support mechanisms provided by national governments.

Wind costs have declined steadily and a typical installed cost for onshore wind farms is now around US$ 1 600/kW, and for offshore around US$ 2 400-3 000/kW. The corresponding electricity costs vary, owing partly to wind-speed variations and partly to differing institutional frameworks. Prices paid for wind-generated electricity are mostly in the range US$ 52-90/MWh (Milborrow, 2007) and at the lower end of this range are competitive with coal and gas.

A review of future costs by the Sustainable Development Commission (SDC, 2005) suggested that installed costs onshore in 2020 will lie between 55% and 92% of the 2001 level. Applying a cautious multiplier of 81% to the 2005 level suggests the 2020 level may be around US$ 1 250/kW. A more optimistic cost projection from the Global Wind Energy Council (GWEA and Greenpeace, 2006) suggests US$ 1 000/kW.

Offshore wind is less well developed, with worldwide capacity around 750 MW, but there are substantial plans in the pipeline. Two of the estimates in the Sustainable Development Commission report suggest installed costs by 2020 will be about 57% of the 2003 level.

Wind Farms

The way in which wind energy has developed has been influenced by the nature of the support mechanisms. Early developments in California and subsequently in the UK, for example, were mainly in the form of wind farms, with tens of machines, but up to 100 or more in some instances. In Germany and Denmark the arrangements favoured investments by individuals or small cooperatives and so there are many more single machines and clusters of two or three. Economies of scale can be realised by building wind farms, particularly in the civil

Figure 12-5 Key features of an onshore and an offshore wind farm
Sources: Scottish and Southern Energy, E2 Energy, Denmark

	Onshore	Offshore
Project name:	Hadyard Hill, Scotland	Nysted, Denmark
Project location:	72 km south of Glasgow, in the Southern Highlands of Scotland	10 km from the coast southeast Denmark
Site features:	moorland, 250 m above sea level	water depth 6-10 m
Turbines:	52 x 2.3 MW	72 x 2.3 MW
Project rating:	120 MW	166 MW
Turbine size:	58 and 68 m hub height, 82 m diameter	69 m hub height, 82 m diameter
Energy production (annual):	320 000 MWh	595 000 MWh
Construction completed:	2005	2003

engineering and grid connection costs and possibly by securing 'quantity discounts' from the turbine manufacturers. Economies of scale deliver more significant savings in the case of offshore wind farms and many of the developments involve large numbers of machines. Fig. 12-5 gives an indication of typical parameters for offshore and onshore wind farms. The offshore project uses machines with the same rating as the onshore project but machine outputs for offshore installations are expected to increase in the future – to 5 MW, and possibly more.

Small Wind Turbines

There is no precise definition of 'small', but it usually applies to machines under about 10 kW in output. In developing countries small wind turbines are used for a wide range of rural energy applications, and there are many 'off-grid' applications in the developed world as well - such as providing power for navigation beacons and road signs. Since most of these are not connected to a grid, many use DC generators and run at variable speed. A typical 100 W battery-charging machine has a shipping weight of only 15 kg.

A niche market, where wind turbines often come into their own as the costs of energy from conventional sources can be very high, is in cold climates. Wind turbines may be found in both Polar regions and in northern Canada, Alaska and Finland.

Environmental Aspects

No energy source is free of environmental effects. As the renewable energy sources make use of energy in forms that are diffuse, larger structures, or greater land use, tend to be required and attention may be focused on the visual effects. In the case of wind energy, there is also discussion of the effects of noise and possible disturbance to wildlife - especially birds. It must be remembered, however, that one of the main reasons for developing the renewable sources is an environmental one - to reduce emissions of greenhouse gases. Several studies have shown that wind plants 'repay' the energy used during construction in about 6 months or less, so that electricity generated after that time realises substantial emission savings. In most cases wind generation displaces coal-fired plant, so 1 kWh of wind saves about 1 kg of carbon dioxide.

Noise

Almost all sources of power emit noise, and the key to acceptability is the same in every case - sensible siting. Wind turbines emit noise from the rotation of the blades and from the machinery, principally the gearbox and generator. At low wind speeds wind turbines generate no noise, simply because they do not generate. The noise level near the cut-in wind speed (Fig. 12-4) is important, since the noise perceived by an observer depends on the level of local background noise in the vicinity, and this has a masking effect. At very high wind speeds, on the other hand, background noise due to the wind itself may well be higher than the noise generated by a wind turbine. The intensity of noise reduces with distance and it is also attenuated by air absorption.

The exact distance at which noise from turbines becomes 'acceptable' depends on a range of factors. As a guide, many wind farms with 400-500 kW turbines find that they need to be sited no closer than around 300-400 m to dwellings.

Television and Radio Interference

Wind turbines, like other structures, can sometimes scatter electro-magnetic communication signals, including television. Careful siting can avoid difficulties, which may arise in some situations if the signal is weak. Fortunately it is usually possible to introduce technical measures - usually at low cost - to compensate.

Birds

The need to avoid areas where rare plants or animals are to be found is generally a matter of common sense, but the question of birds is more complicated and has been the subject of several studies. Problems arose at some early wind farms that were sited in locations where large numbers of birds congregate - especially on migration routes. However, such problems are now rare, and it must also be remembered that many other activities cause far more casualties to birds, such as the ubiquitous motor vehicle.

In practice, provided investigations are carried out to ensure that wind installations are not sited too near large concentrations of nesting birds, there is little cause for concern. Most birds, for most of the time, are quite capable of avoiding obstacles and low collision rates are reported where measurements have been made.

Visual effects

One of the more obvious environmental effects of wind turbines is their visual aspect, especially that of a wind farm comprising a large number of turbines. There is no measurable way of assessing the effect, which is essentially subjective. As with noise, the background is important. Experience has shown that good design and the use of subdued neutral colours – 'off-white' is popular - minimises these effects. The subjective nature of the question often means that extraneous factors come into play when acceptability is under discussion. In Denmark and Germany, for example, where local investors are often intimately involved in planning wind installations, this may often ensure that the necessary permits are granted without undue discussion. Sensitive siting is the key to this delicate issue, avoiding the most cherished landscapes and ensuring that the local community is fully briefed on the positive environmental implications.

Integration into Supply Networks

Electricity systems in the developed world have evolved so as to deliver power to the consumers with high efficiency. One fundamental benefit of an integrated electricity system is that generators and consumers both benefit from the aggregation of supply and demand. On the generation side, this means that the need for reserves is kept down. In an integrated system the aggregated maximum demand is much less than the sum of the individual maximum demands of the consumers, simply because the peak demands occur at different times.

Wind energy benefits from aggregation; it means that system operators cannot detect the loss of generation from a wind farm of, say, 20 MW, as there are innumerable other changes in system demand which occur all the time. Numerous utility studies have indicated that wind can readily be absorbed in an integrated network at very modest cost (IEA, 2005) until the wind contribution on an energy basis reaches about 20% of electricity consumption. Beyond this, some wind power may need to be curtailed on a few occasions if high winds coincide with low demand, but there are no ‘cut-off’ points. Practical experience at these levels is now providing a better understanding of the issues involved.

Future Developments

The very rapid growth in Denmark and Germany, up to around 2003/4, has now slowed, but Spain, India, China and the United States are forging ahead and there are plans for further capacity in Canada, the Middle East, the Far East and South America. If the current growth rate continues, there may be about 150 GW of wind by 2010. The rate of development will depend on the level of political support from national governments and the international community. This, in turn, depends on the level of commitment to achieving carbon dioxide reduction targets. Although the technology has developed rapidly during the past 20 years, further improvements are expected both in performance and in cost.

David Milborrow
Energy Consultant,
United Kingdom

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TABLES

Table 12-1 Wind energy: installed generating capacity and annual electricity output at end-2005

	Installed capacity (MW_e)	Annual output * (GWh)
Algeria	1	2
Cape Verde Islands	3	6
Egypt (Arab Rep.)	230	252
Eritrea	1	2
Kenya	N	N
Morocco	64	220
Namibia	N	1
Nigeria	2	4
Senegal	N	N
South Africa	3	6
Tunisia	20	42
Total Africa	**324**	**535**
Canada	683	1 798
Costa Rica	71	135
Guadeloupe	33	26
Jamaica	21	40
Mexico	2	5
Netherlands Antilles	12	25
United States of America	9 149	17 811
Total North America	**9 971**	**19 840**
Argentina	28	72
Brazil	29	65
Chile	2	4
Colombia	20	40
Cuba	5	10
Peru	1	1
Uruguay	N	1
Total South America	**85**	**193**
Bangladesh	1	2
China	1 266	2 532
Cyprus	N	N
Hong Kong, SAR	N	N
India	4 434	7 160
Indonesia	1	2
Japan	1 078	1 905
Korea (Republic)	99	130

Table 12-1 Wind energy: installed generating capacity and annual electricity output at end-2005

	Installed capacity (MW_e)	Annual output * (GWh)
Nepal	1	2
Philippines	25	17
Sri Lanka	3	2
Taiwan, China	24	23
Thailand	N	N
Turkey	20	64
Total Asia	**6 952**	**11 839**
Austria	819	1 600
Belarus	1	2
Belgium	167	225
Bulgaria	11	1
Croatia	6	10
Czech Republic	22	21
Denmark	3 129	6 614
Estonia	32	60
Faroe Islands	4	8
Finland	82	170
France	723	958
Germany	18 428	27 229
Greece	573	1 270
Hungary	17	10
Ireland	496	1 112
Italy	1 639	2 343
Latvia	25	46
Lithuania	1	2
Luxembourg	35	53
Netherlands	1 224	2 050
Norway	270	507
Poland	124	136
Portugal	1 063	1 770
Romania	1	4
Russian Federation	11	20
Slovakia	5	4
Spain	10 028	20 236
Sweden	493	936
Switzerland	12	8
Ukraine	72	36
United Kingdom	1 565	2 908
Total Europe	**41 078**	**70 349**

Table 12-1 Wind energy: installed generating capacity and annual electricity output at end-2005

	Installed capacity (MW_e)	Annual output * (GWh)
Iran (Islamic Rep.)	25	46
Israel	6	12
Jordan	2	3
Lebanon	N	N
Syria (Arab Rep.)	1	2
Total Middle East	**34**	**63**
Australia	708	2 170
New Caledonia	15	30
New Zealand	168	610
Total Oceania	**891**	**2 810**
TOTAL WORLD	**59 335**	**105 629**

Notes:

1. The data shown largely reflect those reported by WEC Member Committees in 2006/7, supplemented by national and international published sources, in particular: the American Wind Energy Association, the European Wind Energy Association, *IEA Wind Energy Annual Report 2005*, *Windpower Monthly* and the World Wind Energy Association.

* Where data on wind energy output are not available, estimates have been calculated by applying a 22% capacity factor to the end-2005 installed capacity.

COUNTRY NOTES

The Country Notes on Wind Energy have been compiled by the Editors. In addition to national and international Wind Energy Associations' web sites and government publications/web sites, numerous national and international sources have been consulted, including the following publications:

- *IEA Wind Energy Annual Report 2005*, International Energy Agency;
- *Renewable Energy World,* PennWell International Publications Ltd.

Information provided by WEC Member Committees has been incorporated as available.

Albania

Historically wind energy has been used in isolated areas by traditional windmills and for water pumping; however, in recent years attention has turned to utilising the resource for power generation.

The areas of Albania best suited for wind installations have been found to be the mountainous regions of the northeast, the hilly areas of the south and southeast and the coastal strip.

It is considered that by 2020 4% of the country's electricity could be generated by wind power (some 400 GWh/yr). If priority is given to the construction of 20 coastal wind turbines adjacent to water pumping stations, the areas lying beside the Adriatic can be safeguarded from flooding. Pumping stations located in the coastal lowlands take around 30 GWh/yr (some 0.7% of domestic power generation). Studies conducted by the National Agency of Energy have shown that these areas have a sufficient wind resource for them to be considered as suitable sitings for turbines. Average annual wind speed is around 4-6 m/s at a height of 10 m (with an average annual energy density of 150 W/m^2).

Algeria

Algeria has a moderate wind potential, with speeds ranging from 2 to 6 m/s. The area between Adrar–Tindouf and Timimoun in the southwest of the country has been shown to have the best prospects.

The contribution of wind energy in the Algerian energy balance is not high. At the present time the resource is harnessed to good effect in isolated sites and the main applications are for water pumping, especially in the high plains. However, three projects are currently in progress: the completion of a wind atlas, the completion of a 10 MW hybrid power station (6 MW wind / 4 MW diesel) at Tindouf and the hybridisation of an existing diesel plant at Tindouf.

Argentina

Argentina is a country with a good wind resource. It is estimated that currently the Pampa Plain has the highest concentration of wind turbines in the world, with more than 400 000 existing installations. Certainly, the role of wind energy has been significant in the development of the country's agricultural and farming sectors.

With regard to electric power generation, Argentina currently has 12 wind farms located in 5 different provinces, with a total installed power of 27.7 MW. Many of the farms have been developed under the protection of the National System of Wind and Solar Energy passed by Act 25019/98. Among other tax concessions this saw the granting of a US$ 10 subsidy per MWh generated and transferred to the electricity grid. However, Argentina's current use of wind energy bears little relation to its immense potential. It has been calculated that the Patagonian wind potential south of parallel 42 is many times higher than the potential represented by the total annual Argentine oil production. Furthermore, it is not only the southern end of Argentina that presents favourable conditions for the installation of wind farms; there are many other suitable regions: in almost all the territory of the provinces of Río Negro and Neuquén; in many highland and coastal areas of the province of Buenos Aires as well as in many other sites in the rest of the country.

The National Wind Energy Plan, commissioned by the Ministry of Federal Planning and being implemented by the Chubut Regional Wind Energy Centre (CREE), lays the foundations for the first significant national development in this field. The Plan comprises both the compilation of a national wind map as well as the installation of numerous wind farms, with an aggregate power of about 300 MW to be achieved in about three years. The first stage of the Plan comprises the completion of the project Vientos de la Patagonia I (Patagonian Winds I), which comprises the construction of a wind farm of 50-60 MW near the city of Comodoro Rivadavia in Chubut province, although in subsequent stages it foresees the installation of similar farms in the provinces of Santa Cruz, Buenos Aires, Río Negro, Neuquén, La Rioja and San Juan.

Australia

The development of the wind energy sector got off to a slow start in Australia. The resource had been used historically for water pumping in isolated locations but there existed no comprehensive wind industry. The situation began to change at the end of the 1980s (when the first 20 kW grid-connected turbine was installed in Victoria) and gathered momentum during the 1990s. By end-1999, total installed capacity stood at just over 10 MW (wind-diesel hybrid and grid-connected schemes) and the Australian Wind Energy Association (AusWEA) had just been formed.

The Renewable Energy (Electricity) Act of 2000 established the Mandatory Renewable Energy Target (MRET) which came into effect in April 2001. This piece of legislation, the founding of the AusWEA and the establishment of an indigenous wind turbine manufacturing sector are considered to have been fundamental in transforming the country's wind industry. By end-2005 708 MW had been installed across all states, representing the third year in a row in which capacity had nearly doubled. By end-2006, the total had risen to 817 MW, comprising approximately 450 turbines. There are some 40 plants operating, of which 17 are wind-diesel hybrid projects, including Mawson Base in the Australian Antarctica Division.

The MRET scheme was designed to ensure that large energy users and wholesalers purchased 2% of their requirements from renewable sources by 2010. Its success has meant that this target was reached almost twice as quickly as planned. In place of any further mandatory legislation from the Federal Government, some of the State Governments have set their own targets in order to sustain the momentum of the renewable energy market.

The existing national electricity grid is capable of supporting up to 8 000 MW wind capacity - the planned projects are consistent with this level. At end-2006, there was 521 MW under construction and a further 2 109 MW with planning approval, 345 MW seeking approval, 165 MW under tender and 2 339 MW undergoing feasibility studies.

A synergy from combining wind and hydropower has been facilitated by the Basslink interconnector, an undersea cable across the Bass Strait. The cable, which became operational in April 2006, connects Tasmania to the national electricity market via Victoria, allowing Tasmania to supply peaking power at premium prices to Victoria at times of high demand in both summer and winter. It will also enable the export of new renewable energy from wind farm developments to the mainland market.

A considerable amount of wind-related legislation is in place: The National Greenhouse Strategy, the Renewable Energy Action Agenda, the 2004 White Paper on Energy and the Environment, the Green Power national accreditation program, and the Australian Greenhouse Office initiatives are all playing their role in the deployment of renewable energy in general. In order to sustain the growth of recent years it will be necessary for the wind energy industry to overcome various impediments and to implement the relevant policies. but at this stage the outlook for wind is promising.

Austria

Since the mid-1970s the production of renewable energy has grown steadily and has reached a stage where it currently generates 63% of Austria's electricity. Hydropower supplies the majority share and to date the other renewable energies have played a minor role. With a view to changing this balance and taking into consideration the technologies available, wind power - largely available during the winter months - could complement hydro - at its lowest during the winter.

The first wind measurements were conducted in the late 1980s, discussions regarding feed-in tariffs began in 1991 and the first funding programmes commenced in 1994. These actions brought about the first modern wind turbines in 1996.

After growing slowly during the second half of the 1990s, Austria's total installed wind capacity has been rising steadily, from 606 MW at end-2004 to 819 MW by end-2005 and 965 MW by end-2006. Europe's highest wind park was officially opened in 2003. Situated at 1 900 m, the Tauernwindpark Oberzeiring consists of 11 turbines; its total 19.25 MW capacity is expected to produce 40 GWh/yr.

Although Austria does not manufacture wind turbines, it does make important components for the world's biggest producers of wind generators.

The Eco-electricity Act (Ökostromgesetz) of July 2002 came into effect on 1 January 2003. The law's objective is to raise the share of renewables to 78.1% of Austrian electricity consumption by 2010 and the non-hydro portion (the so-called 'new renewable resources') to 4% by 1 January 2008. The Act lays down an Austria-wide uniform purchasing and payment obligation for power suppliers concerning energy from renewable sources, defined as wind, sun, global heat, hydroelectric power, biomass, landfill gas, sewer gas and biogas. The subsidies for eco-electricity are funded via an extra charge on the electricity price. The Tariff Ordinance (Tarifverordnung) to the Eco-electricity Act provides for attractive and nationally uniform feed-in tariffs for electricity from new eco-electricity plants approved up to 2004.

On 23 May 2006 the National Council adopted an amendment to the Eco-electricity Act. The Amendment envisages a 10% share of so-called new renewable resources in power production in Austria by 2010. It refers exclusively to plants to be newly established and provides for a subsidy until 2011. The annual subsidy amounts to € 17 million, of which 30% is apportioned to biogas plants, 30% to biomass plants, 30% to wind energy plants and 10% to other new renewable resources (e.g. photovoltaics). The feed-in tariffs for these plants have to be refixed every year, with tariffs becoming lower in later years. The tariff applying at the time of the conclusion of the contract applies for 10 years. In the 11th year only, 75% and in the 12th year only, 50% of the respective tariff is to be paid, but at least the market price. The Eco-electricity Amendment also lays down criteria of energy efficiency and minimum full load hours for the individual types of energy.

Belgium

With its heavy reliance on nuclear power, Belgium has been slow to deploy wind turbines. However, the planned closure of its seven nuclear stations (between 2015 and 2025) has prompted discussion of how renewable energies could take their place. At the present time, renewable energy accounts for less than 1% of Belgium's electricity generation.

A demonstration wind farm (21 turbines of 200 kW each, one turbine of 400 kW and one of 600 kW) was established on the eastern pier of Zeebrugge harbour in 1986. Another 600 kW turbine was added in 1999. Apart from the contribution the wind farm makes to the local electricity generation, its main purpose has been to publicise and popularise the concept of wind power.

By end-2005 Belgian installed wind capacity stood at 167 MW; by end-2006 it was reported that it had risen to 193 MW.

Brazil

According to the *Atlas do Potencial Eólico Brasileiro* (Brazilian Wind Atlas) the gross wind resource potential is estimated to be about 140 GW. However, only a portion of that amount could be effectively transformed into wind power projects.

In 2002 the Brazilian Government launched PROINFA - Alternative Sources for Energy Incentive Program, a national programme designed to promote the use of wind, biomass and micro-hydro. It was revised in November 2003. The first phase of 3 300 MW included 1 100 MW of wind power.

Although the main application of wind energy in Brazil is for installed capacity to be grid-connected, the end-2005 installed capacity totalled just 29 MW, of which the main installations were as follows:

City	State	Capacity (MW)
Aquiraz	Ceará	10
São Gonçalo do Amarante	Ceará	5
Gouveia	Minas Gerais	1
Palmas	Paraná	2.5
Fortaleza	Ceará	2.4

However, by October 2006 operational capacity had risen to 158 MW.

Bulgaria

Bulgaria's wind energy resources are quite modest. The territory can be divided into four zones according to their wind potential. However, only two of them are of interest with regard to electricity generation: 5–7 m/s and > 7 m/s. The area where the annual average wind speed is in the region of 6 m/s or above is about 1 430 km^2.

Canada

Canada's wind energy capacity has grown significantly during the current decade. By end-2005 Canada had 683 MW installed capacity; by end-2006 it had grown to 1 460 MW from just 138 MW in 2000. Wind generators produced an estimated 1.8 TWh of electricity in 2005.

The federal Government's Wind Power Production Incentive (CDN$ 0.01/kWh) has assisted in the development of wind power generation. It aims to increase wind power to 4 000 MW by 2010. By end-2005 approximately CDN$ 300 million had been allocated for 22 projects, with a total capacity of 920 MW.

Provincial incentives and Renewable Portfolio Standards have also assisted in the development of wind projects. Each Canadian province is planning to increase its wind power capacity. An example of the ambitious programmes for encouraging renewable energy is the Standards Offer Program in Ontario, which provides CDN$ 0.11/kWh for small renewable energy producers. Ontario also has a Renewable Portfolio Standard and aims to generate 5% of its power from renewable energy by 2007 and 10% by 2010. It is expected that up to 80% of this generation will be met through wind power. Saskatchewan has enacted a Green Power Portfolio strategy, stating that all new provincial electricity generation will come from non-GHG emitting sources by 2010. Prince Edward Island (PEI) passed a Renewable Energy Act in 2004 requiring utilities to acquire at least 15% of their electrical power from wind by 2010. Under this Act, there are plans for 59 MW of new wind capacity to be installed in PEI by end-2007. By 2015, Quebec is looking to increase its wind capacity by 4 000 MW, while Manitoba, New Brunswick and Nova Scotia are aiming to add 1 000 MW, 400 MW and 380 MW respectively over the same time period.

According to the Canadian Wind Energy Association, there are 33 projects under development, some of which have signed power purchase agreements and are under construction. Should all of these wind farms be developed, Canada’s wind power capacity will increase by a further 2 800 MW. Of this, the majority of the development will take place in Quebec (1 245 MW) and Ontario (955 MW), with other significant contributions in British Columbia (325 MW) and Alberta (134 MW).

Wind-diesel hybrid projects in remote Canadian communities, operating on an isolated grid, demonstrate that wind energy can offset some of the costs associated with transporting diesel fuel to remote sites. The Government of Canada, through the Technology Early Action Measures and Natural Resources Canada, supported Frontier Power Systems in the installation of hybrid wind-diesel systems on the island of Ramea, in Newfoundland. Further to this, there are some systems online in northern communities, including Rankin Inlet and Cambridge Bay in Nunavut and others in the Northwest Territories. There is also a significant rural Canadian, and potentially large international, market for small non-electric wind turbines for pumping water and aerating ponds.

China

Although the use of the Chinese wind resource for water pumping is many hundreds of years old, it is only in recent years and with the country's rapid economic growth that attention has turned to utilising wind power by means of modern turbines.

The country not only has an enormous energy/electricity generation requirement, an historical reliance on coal and limited indigenous oil resources, but also severe environmental problems. To address these issues, the Government has targeted renewables to supply an increasing share of power output from green energy.

The provinces of Inner Mongolia and Hebei and the eastern coastal areas are well blessed with wind energy. The theoretical potential of the country as a whole has been estimated to be over 3 000 GW, but the Chinese Meteorology Research Institute states that the practical potential is in the region of 250 GW onshore (at 10 m) and 750 GW offshore (at 50-100 m).

The China Renewable Energy Law, issued at the end of February 2005, became effective on 1 January 2006. The legislation is intended to provide the basis for favourable long-term financial arrangements in order to encourage private investors and hence to expedite the development of the wind industry.

The strategic targets set by the Energy Bureau of the National Development and Reform Commission (NDRC) were for 4 GW of installed wind capacity by 2010 and 20 GW by 2020. The targets were subsequently raised to 5 GW by 2010 and 30 GW by 2020. At the beginning of 2007 it was reported that the 2010 target had been raised again, to 8 GW. It has been suggested that these goals could be surpassed, with capacity in 2010 totalling nearly 10 GW and in 2020, 54 GW.

From a very small beginning in 1986, when a pilot wind farm was established in Shandong province, the sector had grown to approximately 1 300 MW by end-2005, a 30% annual increase since 2000. Installed capacity was spread across more than 60 wind farms in 15 provinces. By end-2006, capacity more than doubled to about 2 630 MW. In April 2007 it was reported that installed capacity would reach 4 GW by the end of the year and that the 5 GW target would probably be attained some two years earlier than expected.

The size of installed turbines ranges from 600 kW to 1.5 MW. The national manufacturers are now fully capable of producing turbines up to 750 kW and several large-scale turbines – 1.2 and 1.5 MW – are being tested. However, it is generally felt that it will be necessary for the industry to become expert in producing the larger machines in order to supply the ambitious development plan.

It is estimated that by end-2005 some 65 MW, representing approximately 320 000 small stand-alone turbines, had been installed in remote areas.

Costa Rica

Costa Rica is reputed to have a better wind regime than California and some of the highest average wind speeds in the world. In addition to using the country's geothermal and biomass resources, the Government is demonstrating its commitment to the utilisation of its wind resource in an effort to develop sustainably and reduce GHG emissions.

In 1993 the Costa Rican Government issued a tender for a 20 MW (30 x 660 kW) grid-connected wind plant near the town of La Tejona. The project was designed for the installation of between 40 and 100 turbines on two parallel ridges to the northwest of Lake Arenal. However, many problems were encountered, which delayed the project until the late 1990s. It was not until September 2001 that the turbines were shipped and installation could begin.

A further project, also near Lake Arenal, financed by private and public loans, various banks and the Danish International Development Agency, has been developed. The 24 MW Tierras Morenas wind farm sells approximately 70 000 MWh/yr electricity to the Instituto Costarricense de Electricidad (ICE), the state-owned national electric utility, under a 15-year power purchase agreement.

At the present time Costa Rica is the only country in the Central American isthmus to have wind parks connected to the electrical grid. By end-2002, installed wind energy capacity totalled 62 MW and by end-2005 it had increased to 71 MW.

In September 2006 Econergy International announced that ICE had awarded the company and its partners a 20-year contract to build, own, operate and transfer a 49.5 MW project. Work on the 55 turbine Proyecto Eólico Guanacaste wind park was expected to start in early 2007.

Denmark

With the utilisation of wind energy featuring in each Danish energy strategy, the country has made use of its wind resource since the early 1980s. The installed wind turbine capacity grew slowly but steadily until the mid-1990s when growth became very rapid. This situation continued to end-2002, when capacity totalled some 2 900 MW. At that point further onshore expansion ceased, owing to a substantial rise in the investment risks incurred by the turbine owners selling production on the electricity market. This was caused by a set of complicated regulations and a reduced environmental premium paid to wind power.

The wind energy market was influenced during 2004 by a political agreement that encouraged the establishment of offshore wind turbines, together with the introduction of a market-orientated pricing system for wind, leading to increased R&D. In the same year a second re-powering scheme was launched for replacing wind turbines sited in unfavourable positions with new installations in more suitable locations. Following on, in June 2005, the Government published its *Energy Strategy 2025* in which economically viable on- and offshore wind power will both play a rôle. Environmental considerations are central to the Strategy and within six months the Danish Energy Agency (DEA) had begun to formulate a plan for the siting of offshore wind turbines in the period 2010-2025, taking these into consideration.

At end-2005 total installed wind power stood at 3 129 MW, comprising 5 293 turbines and supplying 6 614 TWh (18.5% of Denmark’s total electricity consumption). Capacity at end-2006 was very similar to the end-2005 position but owing to poor wind conditions during the period generation was over 7% down.

The country has the world's largest offshore wind farms: the 160 MW (80 x 2 MW) Horns Rev installation in the North Sea was commissioned during 2002. It is located 14-20 km offshore from the western Danish coast, off Blaavands Huk. During 2003, a sister farm (Nysted) was installed in the Baltic Sea, south of the island of Lolland. Nysted consists of 72 x 2.3 MW turbines.

The Government's 2004 agreement called for two more offshore wind farms, each of 200 MW and tenders were duly called for. Horns Rev II will be located about 10 km to the west of the existing farm. An EIA was submitted to the DEA in October 2006 which stated that the farm would be commissioned by end-September 2009. During 2005 the DEA received tender bids for a second farm at Nysted in preparation for evaluation.

In addition to supplying the home market, Denmark is a major supplier of wind turbines to the world: during 2004, the two largest manufacturers, Vestas and Siemens had a global market share of more than 40%. There are also many Danish companies specialising in wind turbine component manufacture.

With the highly significant role that Denmark plays in the world wind industry, R&D is of the utmost importance. A multidiscipline consortium comprising the Risø National Laboratory, the Technical University of Denmark, Aalborg University and the Danish Hydraulic Institute plays a significant part in the R&D programme and the first three named are numbered amongst the 40 European partners of the UpWind project. The aim of UpWind, formed in March 2006 and funded by the EU's Sixth Framework Programme, is to undertake research into all design aspects of the 8-10 MW turbines that are considered to be necessary for the wind farms of the future.

Egypt (Arab Republic)

Egypt is endowed with an excellent wind energy potential, especially in the Red Sea coast area where a capacity of 20 000 MW could be achieved, as the annual average wind speed is around 10 m/s.

The *Wind Atlas for the Gulf of Suez*, published in March 2003, identified the areas of greatest suitability for wind farm projects. It included data for 13 sites covering the period from 1991 to 2001 and was undertaken with the assistance of the Danish Government.

Since 1992, 5 MW wind capacity has been in service at Hurghada.

At end-2006 there was 225 MW of installed capacity at Zafarana on the Red Sea coast, developed in cooperation with Denmark, Germany and Spain. The wind farm has 5 separate operating stations:

- Zafarana 1 (50 x 600 kW) became operational in April 2001,
- Zafarana 2 (55 x 600 kW) in May 2001,
- Zafarana 3 (46 x 660 kW) in November 2003,
- Zafarana 4 (71 x 660 kW) in June 2004 and

- Zafarana 5 (100 x 850 kW) in September 2006.

A further 80 MW of capacity planned for Zafarana 6 is due to begin operating in 2008 with German cooperation. Zafarana 7 and 8, each of 120 MW capacity are planned with commissioning dates in 2009. These two latter plants are located in an extension to the west of the originally designated area in Zafarana and are being developed with help from Denmark and Japan.

A new area at the El-Zayt Gulf, some 150 km south of Zafarana, has been identified as being suitable for the installation of wind farms. At the present time feasibility studies are being undertaken for two plants – one of 80 MW with German assistance and another of 220 MW with Japanese assistance.

The *Wind Atlas for the Gulf of Suez* has been expanded to cover the entire country and the data extended to cover the period to 2005. The resulting *Wind Atlas for Egypt* was published in December 2005. It included a study of the migratory bird routes in the Suez Gulf region. This area was found to be a pathway for some 2.5 to 3.5 million birds each year – an essential element to consider when EIAs are undertaken as part of feasibility studies.

Egypt's national energy planning incorporates a target of 3% of electricity demand to be met by renewables by 2010. It is expected that this will be mainly satisfied by wind power.

Ethiopia

It has been found that Ethiopian wind speeds suitable for electricity generation vary across the territory. According to a recent survey, there are several stations with higher than 6 m/s annual average wind speed – the speed generally considered as the minimum necessary for power production. The highest wind speeds measured were in the Mekelle Region at Ashegoda with 8 m/s and Harena 6.84 m/s. Other high wind speed sites were found at Nazareth and Gondar with 6.64 m/s and 6.07 m/s respectively. Wind speeds at around 4 m/s were recorded in Harar, Debre Birhan and Sululta. This work was undertaken in 2005 with the assistance of GTZ of Germany, as part of the TERNA programme (Technical Expertise for Renewable Energy Application). The annual distribution shows a minimum in July and August and two peaks in March and October.

Medium wind speeds of between 3.5 and 5.5 m/s (energy values between 500 and 1 500 Mcal/m^2) exist over most of the eastern part of the country and the central rift valley zone. Such winds provide a promising potential for water lifting in the rift valley settlements, where water is scarce both for irrigation and domestic uses. At the present time there are a dozen wind turbines installed by a Catholic Mission in the Meki-Zeway area to pump water for schools and villages.

By the end of 2006, the management of the Ethiopian Electric Power Corporation (EEPCO) had decided to construct two parks of approximately 60 MW each for immediate implementation. The first turbine is planned to be online by June 2007 (end of the dry season).

Finland

The country possesses a considerable wind energy potential, estimated at more than 300 MW onshore and 10 000 MW offshore and this will play a rôle in meeting Finland's target of 31% of electricity generation from renewable sources by 2010 (although it is foreseen that most of the increase in renewables will be met by biomass). In 2001 the National Climate Strategy included a target for installed wind capacity of 500 MW by 2010 and a vision of 2 000 MW by 2025. By 2004 it was clear that the funds available were inadequate for the 2010 goal to be met. With the present circumstances (funding and regulatory conditions), a more realistic target has been set at 300 MW by 2010.

By end-2005 total installed grid-connected wind energy capacity stood at 82 MW (unchanged from 2004) and by end-2006 had only grown to 86 MW. However, there are projects representing more than 150 MW in various stages of development. Seven plants (totalling 44 MW) are currently either under construction or planned for operation during 2007 and a further 124 MW is planned for 2008.

Wind-powered generation provided 0.2% of national electricity consumption during 2005. In 2006 it was expected that wind would supply 10% of demand in the Åland islands, an autonomous region between Finland and Sweden having its own legislation and energy policy.

There is no specific wind energy research programme but two related programmes (DENSY – Distributed Energy Systems, launched in 2003) and CLIMBUS (Business Opportunities in Mitigating Climate Change, launched in 2004) aim to develop the technological aspects for an enhanced future wind sector.

France

Despite having a considerable wind resource, France has historically not been dedicated to developing either the wind industry in particular or renewable energy in general. The Eole 2005 programme, introduced in February 1996, was designed to promote wind power but the programme did not live up to expectations.

The Electricity Law of February 2000 introduced legislation for opening the French electricity market to competition. Previously Electricité de France (EDF) had both sought tenders for wind installations and subsequently decided which would be selected. The Law thus effectively brought Eole 2005 to an end: it was only in 2003 that the wind sector in metropolitan France began to grow substantially. In both 2003 and 2004 annual growth was around 60% and 2005 saw a near doubling of capacity installed. By the end of the year capacity stood at 723 MW. There was a similar doubling during 2006.

The French Environment and Energy Management Agency (ADEME) estimates that France has an onshore potential of 26 GW and 30 GW offshore.

In September 2005 France's first offshore wind farm was authorised to proceed. The 105 MW plant will be located off the coast of the Seine-Maritime Department. An invitation to tender has been issued for this project. In addition, bids have been invited for seven onshore plants totalling 278 MW.

EDF stated that at end-September 2005, out of a total of 3 251 MW renewable energy sources applying for connection to the national grid, 3 121 MW or 96% concerned wind.

In the context of the long-term plan for investments in electricity generation, an Arrêté of 7 July 2006 specifies the following targets for onshore wind energy: an additional 13 000 MW capacity by end-2015, of which 12 500 MW should be met by 2010; for offshore wind, the comparable targets are 4 000 MW by end-2015, of which 1 000 MW should be met by 2010.

During 2006 the French electricity tariffs for onshore wind and for offshore wind were revised in an Arrêté issued on 10 July.

Germany

The Electricity Feed-in law (Stromeinspeisungsgesetz) was the progenitor of German wind power development in 1991. But the country's growth in wind capacity from just 110 MW at end-1991 to the present day, when it ranks as world leader, is due to further legislation in the subsequent years. In 1997, the Federal Building Code included wind turbines as 'privileged building projects'; April 2000 saw the adoption of the Renewable Energy Sources Act (EEG); March 2001 saw the feed-in tariff model complying with the European State Aid and Competition Law, while in August 2004 the EEG was amended.

The wind industry has been so successful that the German Wind Energy Association (BWE) estimates that with over 64 000 people, it now employs more than the German coal-mining industry.

By end-2005 capacity stood at 18 428 MW, representing 17 574 turbines, and provided approximately 6% of Germany's electricity generation. By end-2006, capacity reached 20 621 MW, with the federal state of Niedersachsen leading with 5 283 MW. Although all states possess capacity, the northern states of Brandenburg, Bremen, Hamburg, Mecklenburg-Vorpommern, Niedersachsen, Nordrhein-Westfalen, Sachsen-Anhalt and Schleswig-Holstein constitute over 80% of installed wind power.

To date, various constraints - physical (deep water), financial and administrative - have prevented the same growth in offshore projects as has occurred onshore. There is currently one 4.5 MW offshore wind farm operating in the North Sea and two (2 MW and 2.5 MW) operating in the Baltic Sea. However, over 30 projects are either in the first phase of construction, approved or planned. Financial concerns over the repowering of older, lower-capacity turbines and finding locations for the siting of new turbines are among the problems facing the onshore wind sector.

However, in early-2007 BWE stated that development of the wind resource should see 30 000 MW capacity installed by 2010 and 48 000 by 2030. Of these figures, onshore (including repowering) would account for 24 500 MW and 28 000 MW respectively and offshore the remainder.

The EEG has provided the main motivation for the development of the German wind resource. For turbines installed in 2005, owners are paid € 0.085/kWh up to a reference output level, with reducing payments for amounts in excess. For turbines installed in subsequent years, the basic rate reduces by 2% each year, so that the price of wind energy gradually approaches the market price for electricity.

Additionally, the Environment Ministry has proposed that the German Renewable Energy Law be revised so that offshore projects would receive a payment (€ 0.091 per kWh) for their electricity output over 12 years instead of the current 9 years. At the present time the payment is restricted to those installations which started operating before 2006 but an amendment would extend this date to 1 January 2008. Further amendments would reduce payments to some onshore wind turbines.

Greece

Greece has a substantial wind resource. The areas of highest potential are the Aegean islands, southern Euboea, eastern Peloponnese and Thrace. Wind power's penetration in the autonomous grid of Crete is, at greater than 10%, amongst the highest in the world (with strongly increasing trends). However, the windiest areas tend to be sparsely populated and to have inadequate transmission facilities.

During the 1990s, deployment was slow, with capacity only growing from about 19 MW in 1992 to 40 MW in 1998.

Until the late 1990s the majority of the wind power capacity was owned by the Public Power Corporation (DEI). The Liberalisation of the Electricity Market Law together with the EU Directive for Greece to supply 20.1% of its electricity from renewables by 2010 have helped to provide the impetus that the development of the wind sector needed.

The years 1999 and 2000 saw high growth in the rate of installation (175% and 107% respectively), since when growth has averaged some 22% per annum. By end-2005 installed capacity had risen to 573 MW and by end-2006, to 746 MW, representing 1 028 turbines. However, as the Hellenic Wind Energy Association suggests, there is much room for improvement and a long way to go before meeting the Government's current target of 3 372 MW by 2010.

The bureaucracy and delays in constructing the grid connections are gradually being overcome with the help of legislation. Law 2941 passed in 2001 removed restrictions on many of the locations for renewable energy projects, simplified licensing procedures and ensured the easier construction of nationwide grid connections. Following the start of liberalisation of the electricity market in 1999, acceleration of the process was enshrined in Law 3175 of 2003. Also during 2003, Law 1726 defined the process for the approval of environmental conditions for renewable developments. A new law (3468) appertaining to the procedure for licensing of renewable energies was passed in mid-2006. Regarding wind, it set out Feed-in tariffs for the wind energy projects in the interconnected grid, wind energy in the non-interconnected grid and offshore wind. Additionally, it listed a three-stage process for licensing: the Production Licence stage which incorporates wind measurements; the Installation Licence stage to cover the relevant administration (including Environmental Impact Studies) and the Operation Licence stage.

Currently, the largest share of capacity is located in eastern Macedonia and Thrace with 29%, followed by Sterea Hellas and Euboea with 27%. Crete represents 17%, the Peloponnese 14%, while the north and south Aegean, Thessaly, Ionion and Attica together account for the remaining 13%.

Wind power R&D is promoted by the Ministry for Development and by a number of public bodies (technical universities, the Centre for Renewable Energy Resources - CRES) and, to a lesser extent, DEI. The MEGAWIND research project, coordinated by CRES and co-funded by the European Commission under the Fifth Framework Programme, is concerned with the development of megawatt-size turbines for high-wind complex-terrain sites.

Hong Kong, China

The land-based wind resource of Hong Kong has been studied by a number of organisations. An interactive wind resource map will soon be available at the Institute for the Environment website at the Hong Kong University of Science and Technology. There are about four hilly areas with average annual wind power densities of more than 550 W/m^2 at a hub height of 60 metres.

Hongkong Electric's (HEC) 800 kW wind turbine at Tai Ling on Lamma Island, which is Hong Kong's first commercial-scale grid-connected wind turbine, was put into operation on 23 February 2006. The 71 m tall, triple-bladed wind turbine is expected to produce about one million kWh annually. It can supplant the need to burn 350 tonnes of coal annually and avoid the emission of 830 tonnes of CO_2.

An important component of HEC's vision for 'Lamma Winds' is heightening public awareness of using wind as renewable energy for power generation. To this end, HEC has created an exhibition centre at the site that provides a wealth of information on the nature of wind and other sources of renewable energy, their benefits and limitations, and examples of their application worldwide.

The pilot project provides valuable insight into the benefits as well as the limitations of utilising wind as renewable energy for power generation in the context of Hong Kong's unique environment. The experience gained is of vital importance for HEC in its pursuit of wider application of renewable energy.

CLP Power Hong Kong plans to install a commercial-scale wind turbine in 2007.

Due to the scarcity of suitable land in Hong Kong, both CLP and HEC are conducting feasibility studies for offshore wind power in Hong Kong waters. The potential total capacity for both projects is 250 MW.

Hungary

The Hungarian wind resource data are only partly known, since measurements were only taken at a height of 30-50 m. The average potential in the central area of the country (Alföld) is around 70 W/m^2 and in the northwest, around 160/180 W/m^2.

Historically there has been little development of wind power in the country but the preferential feed-in tariff (23.8 Ft/kWh) encourages investors. However, as the market is small and the components necessarily imported, the costs of wind energy are high. Furthermore, the national grid has certain limitations on wind power (2005: 200 MW, 2010: 300 MW, 2015: 800 MW) and would need expansion prior to a high growth in grid-connected turbines. Also, the most economic utilisation for wind power in Hungary is for the technology to be combined with pumped-storage hydro plants but it has been found that this solution would need financial assistance from the European Union. It is for all these reasons that to date, energy production from biomass, rather than wind, has been favoured.

Nevertheless, by March 2006 the Hungarian Energy Office had granted licences for 330 MW. Originally, applications for more than this capacity had been received but many were cut back owing to the constraints of the grid.

India

The Indian wind power programme was initiated in 1983-1984 and a *Wind Energy Data Handbook* published in 1983 by the Department of Non-conventional Energy Sources (now the Ministry of New and Renewable Energy, MNRE) served as a data source for early government initiatives. In 1985 an extensive Wind Resource Assessment was launched, which also signalled the beginning of concentrated development and harnessing of renewable sources of energy and, more specifically, of wind energy. To date, seven volumes of the *Handbook on Wind Energy Resource Survey*, containing a huge volume of accumulated wind data, have been published. It is being implemented through the state Nodal Agencies and the Centre for Wind Energy Technology (C-WET). C-WET, an autonomous R&D institution, established by the Ministry and based in Chennai, acts as a technical focal point for wind power development in India.

Estimates of the Indian wind resource have put it at about 45 000 MW (assuming 3% land availability for wind farms requiring 12 ha/MW, at sites having a wind power density in excess of

250 W/m^2 at 50 m hub height). Potential locations with abundant wind have been identified in the following 10 states: Andhra Pradesh, Gujarat, Karnataka, Kerala, Madhya Pradesh, Maharashtra, Orissa, Rajasthan, Tamil Nadu and West Bengal.

In terms of currently installed wind turbine capacity, India ranks fourth in the world behind Germany, Spain and the USA. At end-2005 the figure stood at 4 434 MW. Tamil Nadu possessed over 57% of the commercial plants. By end-September 2006 installed capacity had already grown to 6 018 MW.

Demonstration projects, which began in 1985, are being implemented in areas not already possessing projects but where commercial developments could follow. In early 2006, demonstration capacity totalled 68 MW.

Use is being made of wind-diesel hybrid projects where an area is dependent on diesel fuel. A project with a capacity of 2 x 50 kW has been commissioned in the Sagar Islands in West Bengal. Phase II (8 x 50 kW) is expected to be commissioned shortly.

The strong growth in the Indian wind energy market is expected to continue, and even accelerate, as a result of a range of Government and State-led financial incentives.

Ireland

Ireland's prevailing south-westerly winds from the Atlantic Ocean give a feasible wind resource that has been estimated to be as high as 179 GW, or some 40 times the country's current generating capacity.

This abundant wind supply began to be utilised, albeit rather poorly, in the early 1980s with several demonstration schemes. The detailed investigations that followed included the establishment of the Irish Wind Atlas and, in 1996 the Government's Alternative Energy Requirement (AER I) competition. The market support mechanism of AER I in which 15-year power purchase agreements were awarded to renewable electricity generators has been repeated in further programmes – AER II to AER VI. In 2005 it was announced that the support mechanism to follow AER VI would be based on a fixed feed-in tariff system over a 15-year period but only applying to new capacity projects.

The Government's Renewable Energy strategy, as contained in the 1999 Green Paper and subsequently the 2000 National Climate Change Strategy, specified a target of an additional 500 MW of installed renewable electricity generating capacity to be in place in the period 2000-2005.

The country is also working with the 2001 EU Directive of meeting 13.2% of its electricity generation from renewables by 2010. No target has been specifically set for wind power but it is considered that this resource will make the greatest contribution and the Government has agreed with the relevant parties to work to a figure of 1 100 MW of installed capacity.

By end-2005 capacity stood at 496 MW, a total of 676 MW of capacity was already contracted to be grid-connected by 2011 and some 3 000 MW had been applied for and was in the process of being assessed. By end-2006 installed capacity had climbed to 745 MW.

At the present time, the majority of installed capacity relates to onshore wind turbines but the first phase of the Arklow Bank offshore plant became operational in June 2004. The 25 MW (7 x 3.6 MW) plant, located off the east coast of Ireland in the Irish Sea was co-developed by GE Energy and Airtricity as a demonstration plant. Testing of this first phase will take place for approximately two years, after which a much larger plant may be developed. In 2003 Airtricity agreed with GE Energy to purchase the plant following the testing phase. A new company, Zeusford (50% Airtricity, 50% EHN of Spain) has proposed the expansion of Arklow Bank to a 200 turbine wind farm with a nominal capacity of 520 MW. Some 10% of national electricity demand could be met if the plan comes to fruition.

Italy

The Italian wind resource is most prolific in the southern regions of Campania, Puglia and Molise and on Sardinia, Sicily and the minor islands. Technically exploitable capability for onshore wind farms has been assessed at around 7 000 MW for wind velocity higher than 5 m/s and 90 m hub height. There is a limited potential for offshore development owing to the considerable depth of the coastal waters, although there are possibilities in the seas surrounding Sicily.

Despite the Government's considerable amount of legislation supporting the introduction of renewable energies into the national energy balance, the introduction of wind power capacity has not been as rapid as might have been thought possible. Nevertheless, progress in recent years has been positive, with 789 MW being added between 2003 and 2005. By end-2005 installed capacity stood at 1 639 MW. To date most turbines have been installed in southern areas of the country and the main islands.

The Italian White Paper for the exploitation of renewable energy sources states that the target for wind energy is 2 500 MW for 2008-2012. This position is unchanged since 1999 when the target was established. However, if the present trend continues, it could be expected that between 4 000 and 5 500 MW capacity could be installed by end-2010. These levels are necessary if the country is to comply with the terms of the Kyoto Protocol's CO_2 emissions reduction.

In the past it was thought that problems arose because of difficulties in dealing with an incentive scheme based on Green Certificates and also opposition to the installation of wind turbines from some of the Italian regions and a small number of the environmental groups. However, whereas the Certificates have proved popular with investors and are working well, there is still a certain amount of opposition.

Italy has a wind turbine manufacturing industry. The principal global manufacturer is Vestas Italia, producing medium-size machines. During

2005 the Vestas plant exported 225 turbines not only to other European countries but also to China and the USA. The demand for larger turbines (1-2 MW) continues to increase steadily but policy changes favourable to small turbines will also be likely to boost demand.

Japan

Although the wind resource of Japan is large, located mostly in the far north and far south of the country, there are impediments to utilising it to the full. The areas of high wind (Tohoku, Hokkaido and Kyushu regions) do not match the areas of high population density and the national, privately-owned grids each has a wind capacity limit, ranging from 3.5% to 5% of the grid capacity. Additionally, to date offshore installations have been precluded owing to the deep waters surrounding the country.

Nevertheless, as a result of the UN Climate Change Conference in Kyoto in 1997, Japan agreed to reduce its output of GHG by 6% by 2010, compared to the 1990 level. In order to meet this target, the Government set an objective of 3 000 MW wind capacity in its latest Primary Energy Supply Plan.

April 2002 saw the Government passing further legislation (the Renewables Portfolio Standard - RPS) so that the renewable energy contribution to total electricity supply (1.35% by 2010) would be met.

By end fiscal-year 2001, total installed capacity stood at 139 MW and at end fiscal-year 2005, 1 078 MW. A further 316 MW was added during April-December 2006 to bring the total to 1 394 MW. This high rate of growth has been possible because of Governmental support in the form of field tests, promotional subsidy programmes and the RPS.

Following the results of COP3, the Government must set a further target for 2030. The Japanese Wind Power Association has proposed wind capacity of 11 800 MW by 2030 and the NEDO (New Energy and Industrial Technology Development Organization) suggests that 10 000 MW could be in place by 2020 and 20 000 MW by 2030.

Jordan

Studies on Jordan's wind potential have been conducted over a period of years and have shown that the country has a rich wind energy resource. The average annual wind speed exceeds 7 m/s in some areas. A wind atlas has been prepared based on an assessment of the available resource which demonstrates the existence of a potential for several hundred megawatts of wind-power installations.

There are two operational wind farms in Jordan: Al-Ibrahimiya, with a capacity of 320 kW (4 x 80 kW), established in 1988 in co-operation with a Danish firm and considered as a pilot project; the other, in Hofa, has a capacity of 1 125 kW (5 x 225 kW), established in 1996 in co-operation with the German Government under a programme called Eldorado. Both wind farms are operated and maintained by the Central

Electricity Generating Company (CEGCo). The Ministry of Energy and Mineral Resources (MEMR) has reported that feasibility studies are being undertaken on the possible expansion of both plants. Beginning in August 2005, data were being collected over the course of a year for the site at Al-Ibrahimiya. Subsequent analysis will demonstrate whether the plan will proceed.

The MEMR plan in place during the first years of the 21st century for the development of an IPP wind project was halted. However, having now obtained the necessary agreements and finance from the Global Environment Facility and the World Bank, the MEMR is again preparing studies in readiness for issuing tenders for the construction of a suitable wind plant.

In June 2005 the MEMR contracted with COWI of Denmark to undertake the collection and study of wind data at 15 sites with a view to building a wind project. The 5 most suitable sites will then be further studied, prior to a full feasibility (economic, technical and environmental) study on one of them.

Korea (Republic)

Until a few years ago, Korea concentrated on industrial development goals rather than the advancement of renewable energy utilisation. However, following the Government's establishment of the Basic Plan for New and Renewable Energy (NRE) Technology Development and Dissemination in December 2003, the situation is now changing. A target of 5% of total primary energy supply to be met from renewable energy by 2011 has been set.

Until the end of 2004 implementation of wind power capacity had been extremely slow, totalling only a cumulative 28 MW. However, by end-2005, installed capacity had risen to 99 MW. The NRE goal specifically for wind energy has been put at 2 250 MW installed capacity by 2012. A feed-in tariff for NRE-generated electricity, put in place during May 2002, undoubtedly helps with growth in the wind sector. One particular problem with the future siting of turbines is the lack of suitable locations. The mountainous countryside beyond the centres of population lacks the necessary infrastructure and has other constraints, thus causing capital costs to be higher; moreover obtaining authorisation to build in such areas is often impossible.

An R&D programme was instituted in 2001 and there are now four indigenous turbine manufacturers, mainly working on 750 kW to 2 MW systems. In order to meet the 2012 target, it will be necessary to develop 3 MW class wind systems. In December 2005, a demonstration offshore wind project (two 2 MW systems) was launched.

Latvia

Latvia has favourable conditions for exploiting wind energy: the average yearly velocity of winds blowing over the western coasts of the Baltic Sea is 5.7 m/s.

The Institute of Physical Energetics of the Latvian Academy of Sciences compiled a wind atlas for the country in 1990. It was found that the windiest areas are on the coast of the Baltic Sea (Ventspils to Liepāja) and on the eastern side of the Gulf of Riga (Ainaži). The width of the territory along the former is 50-70 km and of the latter (as far as Ainaži), about 10 km; the total area involved is approximately 10 600 km^2.

Inland, the wind regime is also suitable in the vicinity of Riga, Bauska, Rēzekne, Saldus, Cēsis and Dagda, as well as the windy, hilly areas in Kurzeme, Vidzeme and Latgale (but not on the leeward side of the hills in Jūrmala, Kurzeme, Vidzeme and Latgale).

The tradition of using wind energy in Latvia was revived in 1989, when the first wind power plant (WPP), with a capacity of 16 kW, was installed. Initially, the WPPs operated in the offline mode, with their output used for heat production. Two plants, on the northwest coast of Latvia in the Ainaži region, with a total capacity of 1.2 MW, were connected to the power grid in 1995.

Three WPPs (Nordex turbines) of 3.0 MW were installed on the coast in the neighbourhood of Ventspils between 1999 and 2002.

Also during this period, construction of a wind park began in the Liepaja district. It consisted of 33 directly-driven WPPs of the E-40 type (Enercon turbines) with a total capacity of 22 MW, constituting the largest such park in the Baltic States. The cost of construction was estimated to be US$ 22 million. Generation began in December 2002.

The sole purchaser of wind-generated energy is the state joint-stock company, Latvenergo.

At the present time about 100 MW of WPP is planned for installation over a period of 15 years.

The Institute of Physical Energetics has undertaken research into the construction of directly driven low-power WPPs with the aim of producing inexpensive and optimally designed plants.

Lithuania

The first wind plants were constructed in Lithuania in 2004. Installed capacity of 0.9 MW generated output of 1.2 GWh during the year.

The aggregated planned capacity of wind power plants to be constructed by 2010 is about 200 MW. The Lithuanian Government approved regulation No 1474, 'Procedure for the Promotion of Purchasing of Electricity Generated from Renewable and Waste Energy Sources' on 5 December 2001. This regulation promotes wind generation, with a feed-in tariff (€ 0.0637/kWh) being applied to the purchase of electricity generated by wind power plants.

Mexico

The present resource estimate is of the order of 5 000 MW with the main area of interest being the Isthmus of Tehuantepec where 2 000 MW or more could be installed with a utilisation of about 40%. Other areas of potential are located in the

States of Yucatan, Zacatecas, Baja California Sur, and Tamaulipas.

It has been estimated that Mexican electricity consumption will grow at 5.2% per annum between 2005 and 2014. To satisfy this demand some 22 GW of additional generating capacity will be required. There is thus an opportunity for the country's wind resource to contribute a portion of this new capacity in the coming years.

The national electric utility CFE has plans for 404 MW of new wind capacity for installation during the next 10 years, in groups of 101 MW. There are also private projects of more than 400 MW which have already received a permit from the Mexican Energy Regulatory Commission. With funds from GEF, administered through the UNDP, a large project is being carried out through the Instituto de Investigaciones Electricas to assess the wind potential in certain areas of Mexico and to build a Regional Wind Technology Centre. Wind-based water pumping is widely used, mainly in the north of the country.

By end-2006, the second phase of La Venta wind plant was operational. The 83 MW (98 x 850 kW) La Venta II brought Mexican installed capacity to 85 MW.

Morocco

Study has shown that the best wind resources in Morocco are found in the north (particularly in the Atlantic coastal regions) and in the south. The former experiences annual average wind speeds of between 8 m/s and 11 m/s and the latter of between 7 m/s and 8.5 m/s. The wind potential can be utilised for both grid-connected electricity production and also water production by desalination.

The Centre for Renewable Energies (CDER) has stated that its objectives are that by 2012 20% of electricity and 10% of energy consumption should be supplied by renewable energy. The harnessing of Morocco's excellent wind potential began in 2000 with the 50 MW El Koudia El Baida at Tétouan. This was followed in 2001 by a 3.5 MW plant at the same location. During 2005, output from the two wind farms totalled 208 GWh. In September 2005 a 10 MW plant attached to the cement factory in Tétouan became operational. The grid-connected turbines are expected to produce 38 GWh/yr and provide 50% of the factory's consumption.

In the short term two new wind farm projects are planned by the Moroccan Office national de l'électricité (ONE). It is foreseen that a 60 MW system at Cap Sim, 15 km south of Essaouira, will be operational in 2007-2008. Invitations to tender for a 140 MW (165 x 850 kW) project, split between Dhar Saadane, 22 km southeast of Tanger and Beni Mejmel, 12 km east of Tanger were issued in early 2007. It is foreseen that the project will be operational by 2009-2010.

Many other sites for both large and small projects are currently under development, undergoing feasibility studies or awaiting approval. One desalination project quoted by CDER is a grid-connected wind farm at Tan-Tan city, some 900 km south of Rabat. It is forecast that the plant would begin with 5.6 MW of capacity, rising to 8.8 MW and then to 11.2 MW. By 2015 over 11 000 m^3/d of water could be produced.

Namibia

A full study has been conducted in order to determine the feasibility of wind farms situated on the coastal areas of Namibia. At Luderitz the average wind speed is 7.5 m/s while at Walvis Bay it has been found to be slightly above 7.5 m/s.

A 220 kW wind turbine was installed at Walvis Bay in late 2005 and is to date the largest such installation in the country. There are several other stand-alone 1 kW turbines located around the country used for electricity generation and water pumping for farms, totalling in the region of 70 kW.

The Ministry of Mines and Energy state that at the present time no wind energy projects are planned but with a plentiful wind resource available, there are opportunities for investment.

Netherlands

During 2001 the Dutch Government set new renewable energy targets in order to comply with its obligations under the Kyoto Protocol. These targets were confirmed during 2005, namely that renewable energy should provide 5% of total energy supply in 2010 and 10% in 2020, and 6% of electricity generation in 2005 and 9% in 2010.

In 2001 renewable energy had only a 1.3% share of overall energy consumption and 2.8% of electricity generation and it was felt that without further action future targets could not be met. Taking this into account, government policy attached a higher priority to those renewable energies which it was felt could make the greatest contribution: namely, offshore wind and biomass.

Until 2001, wind capacity had been increasing only slowly, with just 485 MW being installed by year-end. Thereafter, additions to capacity accelerated: 2002 and 2003 saw increases of 38% and 35% respectively and, although the rate of growth was lower in 2004 and 2005 (18% and 14% respectively), the turbines operational at end-year 2005 totalled 1 224 MW.

Study has shown that the available part of the Netherlands Exclusive Economic Zone (NEEZ) could support up to 6 000 MW of offshore wind capacity. The Government has built this figure, along with 1 500 MW of further onshore capacity, into its target that wind power should generate approximately 20% of domestic electricity demand by 2020. In the shorter term, the Ministry of Economic Affairs has agreed with the Dutch parliament that a maximum of 700 MW of offshore wind capacity should be in place by 2010.

Early in 2002 the consortium Noordzeewind (Nuon Renewables and Shell Wind Energy) was chosen to build a demonstration Near Shore Wind Farm (NSW) off the coast at Egmond aan Zee. The NSW is designed to have a life span of

20 years, at the end of which it will be dismantled. The intention is that the experience gained will greatly assist the development of further offshore installations, both larger in size and located in deeper waters. Construction of NSW began during 2005, the final turbine was erected in August 2006 and the first electricity supplied in October 2006. The research programme will last until 2012.

Construction began on the 120 MW Q7 wind farm, some 23 km offshore from Ijmuiden, in late 2006. The project is being developed by Econcern, Energy Investments Holding and ENECO. It is expected that the first electricity from Q7 will be generated in early 2008.

In January 2007, it was announced that the EIA for WEOM's (Wind Energy Development Company) 270 MW offshore wind farm, Den Haag II, had been issued and was open for inspection.

Along with Germany and the UK, the Netherlands is part of the European Offshore Supergrid® project. Initially 10 GW, the Foundation Project is designed to test the feasibility of interconnecting 2 000 wind turbines and supplying electricity to the national grids of all three countries. Ultimately, it is proposed that the system could cover the Baltic Sea, the North Sea, the Irish Sea, the English Channel, the Bay of Biscay and the Mediterranean.

New Zealand

A wealth of indigenous renewable energy (in particular hydro and geothermal) already supplies about 30% of total energy demand and about 70% of electricity supply. However, owing to its location, New Zealand also has an excellent wind resource that will be increasingly harnessed in the future. The Government's National Energy Strategy and Domain Plan for Energy Sector 2006-2016 acknowledge the importance of the country's wind resource amongst the renewable energies in helping to provide a sustainable source of energy and security of supply in the coming years.

At end-2003 total installed capacity stood at just 36 MW but during 2004 three wind farms (Te Apiti, Tararua 2 and Hau Nui 2) came online bringing total capacity to 168 MW. With just one 100 kW turbine becoming operational during the following year, capacity effectively remained unchanged at end-2005. Five of the planned 97 turbines at Te Rere Hau wind farm were added during 2006 bringing the total to 171 MW.

The situation is set to improve in 2007 with the 58 MW White Hills and 93 MW Tararua 3 wind farms being completed. Furthermore, projects representing over 1 500 MW are in various stages of authorisation – an indication that the NZ wind sector has ambitious plans for growth.

Norway

Norway's electricity production is virtually entirely based on hydropower but as there are physical limitations to new schemes, attention has turned to wind energy, albeit with some major obstacles to overcome (financing, public acceptance, etc.).

Although the country has a tremendously high wind resource, in some remote areas the prohibitively high cost of grid connection would make installation of wind turbines uneconomic. Until 2002 installed capacity was extremely small but during the year two 40 MW projects (on the island of Smøla and near the town of Havøysund, close to the North Cape) became operational, bringing total capacity to 97 MW. Further growth occurred during 2004 and 2005 bringing the total to 270 MW. However, as electricity generated from wind was only about 500 GWh in 2005, it represented a very minor part of the total electricity generation of 138 TWh.

Enova, an enterprise owned by the Norwegian Ministry of Petroleum and Energy came into operation on 1 January 2002. Its mission is to ‘contribute to environmentally sound and rational use and production of energy, relying on financial instruments and incentives to stimulate market actors and mechanisms to achieve national energy policy goals’. One of Enova’s goals is to install 3 TWh of wind power by 2010. This target represents approximately 1 000 MW of capacity. By end-2005 Enova had signed contracts for 12 projects totalling approximately 500 MW and 68 MW were under construction. Also by end-2005 there were plans for 8 000 MW wind turbines but it was felt that the price for electricity had not risen to a level high enough to provide the incentive for development.

Following the 2005 general election and the establishment of a new Government, a period of uncertainty regarding the continuance of a green certificate scheme came to an end. The Ministry of Petroleum and Energy presented a new support scheme for renewable energy in November 2006 but it will not become effective until 2008. Wind power will receive a feed-in support of 8 Norwegian øre/kWh for 15 years in excess of the marked price (approximately € 10/MWh). For every øre above a marked price of 45 øre, the feed-in will decrease by 0.6 øre.

An indication of the increased drive towards the development of wind power was the formation of the Norwegian Wind Energy Association in April 2006.

Peru

The Peruvian WEC Member Committee reports that the compilation of maps and a wind atlas has been planned for the year 2007.

At the present time there are two grid-connected pilot wind generators: Malabrigo (250 kW), located 750 km north of Lima, and Marcona (450 kW), located 600 km south of Lima. ADINELSA (Empresa de Administración de Infraestructura Eléctrica), considers that it is feasible to install wind farms at Malabrigo (30 MW) and Marcona (100 MW) in due course.

Although wind energy is used for water pumping in various locations, no data are available.

The National Rural Electrification Plan, 2005-2014 contains a programme for the installation of 124 wind generators of 50 kW each, that can vary with the demand. It has been estimated that an investment of US$ 16.5 million would be required for 62 MW of capacity, benefiting 136 000 inhabitants.

Poland

The highest wind velocities in Poland are found along the Baltic coastal region (5-6 m/s annual average wind speed at 30 m above ground level) and in northern and central areas (4.0-5.5 m/s): it is therefore these areas that are the most favoured for development. Wind turbines have been installed in various parts of the country but they are all less than 1 MW capacity. To date it has only been in the north that wind farms of between 1.2 MW and 50 MW have been installed.

Prior to 2001 Polish wind energy capacity stood at a very low level, but the start of operations at the Barzowice (5 MW) and Cisowo (18 MW) plants brought end-2003 capacity to 57 MW. Further development brought the installed capacity to 123.5 MW at end-2005 and to 175 MW at end-2006.

The Polish Wind Energy Association has reported that many wind projects are either planned, under construction or nearing completion (some with participation by Danish, Dutch, Japanese and Spanish companies). The Polish Government plans that by 2010 wind energy capacity will total 2 000 MW and wind power will contribute 2.3% of energy consumption.

Portugal

Despite Portugal's considerable technical wind potential - estimated to be approximately 700 GWh/yr - the country has been slow to utilise it for the production of electricity. However, in recent years, because of a lack of indigenous energy resources and a high dependence on imported fuels, the Government has legislated for electricity to be increasingly produced from renewable energies and in particular wind. The targets for wind power to supply electricity generation are 3 750 MW by 2010 and 5 100 MW by 2013.

The Atlantic archipelagos of the Azores and Madeira both have a high wind energy potential and it was in these islands that the first wind parks were established at the end of the 1980s/beginning of the 1990s.

With the favourable climate that has been created by the new policies, installed operational wind capacity in mainland Portugal and the islands at end-2005 stood at 1 063 MW, a quadrupling of the 2003 capacity. A majority (some 98%) is located on the mainland but the Azores and Madeira have a small number of wind turbines. A significant increase was again demonstrated in 2006 with capacity growing by over 60%. Whilst a proportion of capacity is grid-connected, the Government mounted a drive for more grid-connection of wind farms in 2005.

A measure to promote competition in the power market, the Iberian Market on Electric Energy (MIBEL) – linking the power systems of Portugal and Spain – has experienced many delays since the protocol was signed by the two countries in 2001. Originally, operation of MIBEL was scheduled for January 2003 but the electricity derivatives market finally began to operate only on 1 July 2006.

Study of the country's offshore wind resource is currently being undertaken, as although it does not have the same potential as in northern Europe, it is nevertheless considered that further research is warranted.

Romania

The wind energy potential of Romania has been shown to be significant. A wind map for the country has been developed taking into account the wind source at an average height of 50 m, based on meteorological and geographic data. The wind potential has been estimated at 8 000 GWh/yr.

The planned projects and research programmes are designed to promote investment projects aimed at providing optimum conditions for the development of medium and long-term applications.

For the utilisation of the wind energy resource, a series of investment projects have been proposed aimed at ensuring:

- wind potential utilisation in highly energy-efficient conditions;
- promotion of the technical and functional performance of grid-connected wind turbines;
- creation of prerequisites for the transfer of non-conventional technology and equipment from EU Member States and countries with advanced experience in this field;
- implementation of applied management programmes and technology transfer for wind generators, thereby attracting representatives from the private sector and encouraging them to participate both economically and financially.

Current applications comprise wind power plants; rural electrification; hybrid PV/wind small off-grid public & private systems; and hybrid PV/wind for telecommunications.

It will be necessary for the Romanian Government to promote financial mechanisms to encourage the development of renewable energy and, in particular, commercial wind energy projects.

Russian Federation

Russia has used its high wind resource for many hundreds of years, mainly mechanically for water pumping. However, despite an enormous potential, commercial, large-scale utilisation has never occurred and development has generally been restricted to agricultural uses in areas where a grid connection was infeasible. The areas of greatest resource are the regions where the population density is less than 1 person per km^2.

The coastal areas of the Pacific and Arctic Oceans, the vast steppes and the mountains are the areas of highest potential. In 1935 the wind resource was estimated at 18 000 TWh for the USSR as a whole. More recently, estimates suggest that the European part of Russia has a gross wind energy resource of 29 600 TWh/yr (37%) and the Siberian and Far East part, 50 400 TWh/yr (63%). The technical resource for each is reported to be 2 308 and 3 910 TWh/yr, respectively.

It has been suggested that large-scale wind energy systems might be applied in areas where the resource is particularly favourable and there is an existing power infrastructure and major industrial consumers. These would include various locations in Siberia and the Far East (east of Sakhalin Island, the extreme south of Kamchatka, the Chukotka Peninsula in the Magadan region, Vladivostok), the steppes along the Volga river, the northern Caucasus steppes and mountains and the Kola Peninsula. Additionally, offshore wind parks could be considered in some of these areas, especially in the Magadan region and in the Kola Peninsula where existing hydropower stations could be used to compensate for the intermittent wind power.

During the past decade, Russia's economic constraints have not assisted in the development of large renewable energy projects. However, in 2000, the European Union and Russia began the mutually beneficial Energy Dialogue dealing with a wide range of energy issues, from security of supply to energy efficiency to discussions regarding an interconnected electricity network. Soon after Russia's ratification of the Kyoto Protocol in October 2004, the EU began providing technical assistance through its TACIS programme. The Kyoto Protocol requires the promotion of renewable energy and, as far as wind is concerned, the manufacture of wind energy equipment and the development of wind plants in Russia.

At end-2006, total installed wind capacity stood at 15.0 MW. The main wind power stations are: Kalmickaya, 2.0 MW (Kalmykia); Zapolyarnaya, 1.5 MW (Komi); Kulikovskaya, 5.1 MW (Yantarskaya region); Tyupkildi, 2.2 MW (Bashkiriya) and on Observation Cape, 2.5 MW (Chukotskaya autonomous region).

Feasibility studies are being carried out on the 50 MW Kaliningradskaya and the 75 MW Leningradskaya wind power projects; European and US companies are considering participation in their construction.

Spanish and German companies are considering involvement in 100 MW of wind projects in Kalmykia and in the Krasnodar region.

The Russian Association of Wind Industry (RAWI) was established in the early years of the

21st century and the first of its stated aims is to help the formation, growth and development of the wind power market in the Russian Federation.

South Africa

In recent years South Africa has embarked on a more formal wind exploitation programme. Between August 2002 and February 2003 Eskom erected a small experimental wind facility with a total of 3.2 MW. The purpose of the wind farm at Klipheuwel in the Cape is primarily to gain experience in different turbine technologies.

A privately owned facility in the Darling district in Western Cape has received a licence and will shortly begin construction, subject to procurement of turbines. The first phase is expected to have a capacity of 5.2 MW (4 x 1.3 MW). A second phase incorporating a further 6 x 1.3 MW turbines may be installed later, bringing the total to 13 MW.

A Baseline Study on Wind Energy completed in February 2003 provided the following estimates of annual national electricity output from wind at that point in time: national grid 5 000 MWh; rural mini-grid 111 MWh; off-grid 1 117 MWh; and borehole windmills 26 000 MWh, giving a total of 32 228 MWh.

Spain

Estimates have shown that the country has a technical wind potential of 15.1 GW, which has provided the wherewithal for an ambitious wind energy policy. From a capacity of just 75 MW in 1994, the end-2005 level was 10 028 MW. By then Spain was second in terms of global installed power, lying behind Germany and ahead of the USA (a position retained at end-2006, with an installed capacity of 11 615 MW).

Incremental wind capacity added since 2000 has resulted in historical programmes and forecasts being outstripped. The main impetus behind wind energy's strong position in the Spanish energy market has been the Spanish Renewable Energy Plan 2005-2010, issued by the Instituto para la Diversificación y Ahorro de la Energía (IDAE) in July 2005. The Plan specified that renewable energy (including large hydro) should supply 29.4% of electricity demand by end-2010 and at least 12% of total energy use. The target for wind capacity which had been set at 13 000 MW, was raised to 20 155 MW by end-2010.

Additionally, through a new support scheme for renewable energy, there is a strong incentive to connect wind farms to the electricity market: the price - related to the Average Electricity Tariff (AET) - paid for wind-farm generated electricity is guaranteed for the life of the installation.

Almost all of the Spanish autonomous communities possess wind capacity, from Valencia on the east coast with 20 MW (at end-2005) to Galicia in the north-west with 2 452 MW; only three mainland regions have none.

Although the market has experienced some delays in recent years, owing to administrative difficulties, the autonomous communities have ambitious plans for installations to total some

37 000 MW between 2010 and 2012, of which Andalusia plans 4 000 MW; Catalonia 3 000 MW; Castilla Leon 6 700 MW; Galicia 6 300 MW; Castilla La Mancha 4 450 MW; Aragón 4 000 MW; Canary Islands 890 MW and Valencia 2 400 MW. Several regional governments are also favouring the promotion of small wind farms of less than 5 MW.

Indigenously-owned manufacturers account for over 70% of wind turbines installed in the country. Whilst there are several foreign manufacturers in the market, the national company Gamesa has 50% of the home market. Since 1992 the average size of turbine has been on a rising trend and by 2005 stood at approximately 1.3 MW. However, the size favoured by the developers has grown to 2 MW, in order to maximise the use of land and minimise the environmental factors.

Sri Lanka

A large section of the Sri Lankan population is without access to electricity and whilst hydropower provides the majority of the generated power, this dependence is vulnerable to drought. In order to increase electricity coverage as well as to satisfy the rapidly growing demand for power, much extra capacity will be required.

In June 2003 a USAID-funded solar and wind mapping survey was presented to the Sri Lankan Government. The survey, conducted by the US National Renewable Energy Laboratory, identified various locations along the northwestern coast and the central hill areas for further exploratory work.

At the present time a 3 MW pilot wind project is operating at Hambantota in the south of the country and various small village projects for powering computers, televisions and radios are being implemented. Further projects have been proposed for Bundala, Kirinda and Palatupana.

It has been reported that the Ceylon Electricity Board ultimately hopes to have 200 MW grid-connected wind capacity in the south-eastern quarter of the island.

Sweden

Although Sweden was one of the early pioneers in modern wind power development, embarking on a wind energy programme in 1975, bureaucratic procedures have meant that deployment has been fairly slow.

In 2002 the Parliament set a national planning target of 10 TWh for electricity production from wind power (4 TWh onshore and 6 TWh offshore) by 2015. The Swedish Energy Agency (SEA), in an effort to simplify the administrative procedures, apportioned this target regionally with both the available resource and the region's electricity consumption taken into account. During 2005 information received from 19 of the 21 counties suggested that some 1.5 TWh of capacity was planned.

Three programmes to encourage the growth of wind power have been set for the country: 1) quota-based green certificates (favourable to wind power), 2) production support or 'environmental bonus' (declining each year until zero is reached in 2009 for onshore wind) and 3) the SEA has designated 49 areas in 13 counties as being of national interest from the point of view of wind power. Decisions on permit applications will judge this aspect against other national interests (environmental, etc.).

By end-2005 installed capacity totalled 493 MW with 760 turbines generating 936 GWh during the year. By end-2006 capacity had grown to around 570 MW.

The Invest in Sweden Agency stated in August 2006 that: a total of 128 turbines, capable of generating 2 TWh/yr will be built at a site known as Kriegers Flak, 30 km south of the coast at Trelleborg; that four wind power coordinators had been appointed by the Ministry of Sustainable Development in order to facilitate future investment; and that the Environmental Protection Agency had identified 12 offshore sites, suitable for wind power development.

Taiwan, China

On land there is an area of over 2 000 km^2 with an annual average wind speed of 5-6 m/s, an estimated wind power potential of 3 000 MW and an exploitable potential of at least 1 000 MW. With regard to offshore wind energy, it is estimated that the exploitable potential is approximately 2 000 MW. Thus the country's total exploitable wind energy is some 3 000 MW.

The Bureau of Energy reports its R&D wind projects as:

- the Overall Development and Promotion of Wind Energy (2006-2008);
- development of Interconnection Technologies for Distributed Generation (2006);
- development of key components of wind power system (2006-2008).

Taiwan Power Company reports its wind power projects as:

- First Phase (Jan. 2003-Dec. 2006): 60 units to be installed with a total capacity of 98.96 MW;
- Second Phase (Jan.2005-April 2008): 63 units to be installed with a total capacity of 126 MW;
- Third Phase (Jan. 2007-June 2011): 52 units to be installed with a total capacity of 104 MW.

Tanzania

The WEC Member Committee for Tanzania reports that based on the available information, much of the wind resource is located along the coastline, the high plateau regions of the Rift Valley, on the plains and around the Great Lakes. Currently wind energy is used to pump water for irrigation and to meet domestic and livestock water needs. More than 120 windmills have been installed to provide mechanical power for water pumping.

Microscale electricity generation from wind has been reported in a very few locations, while several studies on wind are being carried out in order to establish dissemination strategies for wider application, including power generation. By 2003 more than 8.5 kW of wind-powered electricity generating capacity was in place.

At present the proven potential of wind is 0.9 – 4.8 m/s. At some locations the spot measurements are as high as 12 m/s.

There has been limited success, even in areas with a good wind regime, owing to:

- a lack of reliable wind resources data for siting of wind turbines;
- poorly designed or expensive prototypes;
- a lack of trained local support personnel and maintenance.

There have been few attempts made to utilise wind power, which could be a viable alternative source of energy. However, it has been proposed as an alternative source of electricity, and thus wind-speed data from a site called Setchet is being used to illustrate the possible utilisation for electricity generation. The windy season (July to November) coincides with the dry season. The annual average wind speed during this period is 8.3 m/s, quite high enough for electricity generation via wind turbines.

Tunisia

Two small experimental wind projects: Aquaria (10 kW) and Jabouza (12 kW) (both now closed) had been commissioned during the 1980s by SEN (Société d'Energies Nouvelles). STEG (Société Tunisienne de l'Electricité et du Gaz) took over the wind turbines when SEN closed in 1994. An early 1990s feasibility study undertaken by STEG led to the 10.56 MW grid-connected wind plant at Sidi Daoud becoming operational in August 2000. An 8.72 MW expansion to Sidi Daoud became operational in 2003 and a further expansion of 34 MW is scheduled.

It has been estimated that the wind potential of Tunisia could support 1 000 MW nationwide. Exploratory studies in the north of the country are further advanced than in the remaining territory and three projects totalling 120 MW (Metline, Kechabta and Ben Aouf in the Bizerte region) are due to be operational there in 2009.

Turkey

The wind potential of Turkey has been estimated to be as high as 88 GW but to date very little utilised. At end-2005 total installed capacity stood at only 20.1 MW. However, in mid-2005, one year after the Turkish Parliament approved a first draft law on the use of renewable energy for electricity production, a further law permitting a feed-in tariff was adopted. The tariff will provide renewable energies a purchase guarantee of the average wholesale electricity price for seven years and in particular favour the development of wind energy.

Turkey's installed wind power more than doubled in June 2006 with the commissioning of the 30 MW Bares II plant at Bandirma on the coast of the Sea of Marmara.

Capacity totalling approximately 100 MW is under construction. A further 1 286 MW of capacity has been licensed and 4 076 MW has licence applications in progress.

Ukraine

The wind power potential in Ukraine, whilst very large overall (estimated at some 30 TWh/yr), is considerably higher in the south than in the northern areas. It is considered technically feasible and advisable to use 15-19% of this inherent wind energy. Study has shown that this potential could support up to 16 000 MW (and possibly as much as 35 000 MW).

In line with other European countries Ukraine plans to restructure its energy sector, incorporating a higher utilisation of renewable energies. The Ukrainian Renewable Energy Agency, using the basic assumptions from the draft Energy Strategy of Ukraine for the period to 2030 and the work of INFORSE (V*ision 2050* - energy sector scenarios for European countries), has formulated its own set of scenarios and restated targets that should be met by 2050.

Whilst Ukraine has indigenous fossil fuel resources, it is apparent that they cannot completely satisfy either current or future energy demand. The long-term plan is to utilise the country's varied renewable resources. With regard to wind power, although the present level of installed capacity is quite low, an average wind velocity of 5–5.5 m/s at a height of 10 m available in many regions could lead to a considerable increase in capacity.

At end-2005 total installed capacity stood at 72 MW of which the main plants were: Donuzlavs'ka, 10.9 MW; Sudaks'ka, 5.4 MW; Novoazovs'ka, 20.4 MW; Saks'ka, 18.4 MW; Tarkhankuts'ka, 11.1 MW. It has been predicted that by 2030 over 11 000 MW of capacity will have been constructed and that wind power generation could rise from nearly 25 TWh in that year to around 42 TWh in 2050.

United Kingdom

The Utilities Act (2000) made substantial changes to the regulatory system for electricity in Great Britain. The Act replaced the Non-Fossil Fuel Obligation Orders (NFFO), by the Renewables Obligation and the Renewables Obligation (Scotland), which came into force in April 2002. These impose an obligation on all electricity suppliers to supply a specific proportion of electricity from renewable sources. The target began at 3% in 2003, will rise gradually to 10% by 2010, to 15% by 2015 with the eventual aim of a 20% contribution. In the short term it is likely that wind energy will be the major contributor to meeting these targets, but in the longer term other technologies will come into play.

The Energy Act of 2004 has provided the impetus for the development of wind energy in the UK. It established a comprehensive legal framework for all offshore energy projects, extended the boundary for projects to 200 miles beyond the country’s territorial waters, created a Renewable Energy Zone (REZ) adjacent to the territorial waters in which projects could be installed and provided a framework for the execution of the British Electricity Trading and Transmission Arrangements (BETTA). BETTA came into effect on 1 April 2005 and provides sets of rules both for trading electricity across Britain and for access to and charging for the transmission network,

Thus in recent years great progress has been made in the growth of the UK’s wind energy sector. From just 427.2 MW - 423.4 MW onshore, 3.8 MW offshore - at end-2001, the 1 GW mark was passed in June 2005 with end-year capacity standing at 1 565 MW - 1 351.2 MW onshore, 213.8 offshore. The four operational offshore wind farms in 2005 consist of three in England; off the north east coast at Blyth (3.8 MW), off the east coast (East Anglia) at Scroby Sands (60MW), off the south east coast at Kentish Flats (90 MW) and one off the north coast of Wales at North Hoyle (60 MW). A 90 MW offshore wind farm in the Irish Sea off the north west coast of England at Barrow was officially opened in September 2006.

The UK Department of Trade and Industry reported that as at July 2006, plans for a further 6 200 MW of onshore wind capacity and 3 900 MW of offshore capacity had been published, although it was unlikely that all projects would obtain the necessary permissions to proceed. In early 2007 the British Wind Energy Association (BWEA) listed four offshore projects as under construction, totalling 294 MW and a further ten, totalling 2 484 MW, as having received approval.

The commissioning of the 72 MW Braes of Doune wind farm in Scotland in February 2007 saw total UK installed capacity pass the 2 GW mark.

Along with Germany and the Netherlands, the UK is part of the European Offshore Supergrid® project. Initially the 10 GW Foundation Project is designed to test the feasibility of interconnecting 2 000 wind turbines and supplying electricity to the national grids of all three countries. Ultimately, it is proposed that the system could cover the Baltic Sea, the North Sea, the Irish Sea, the English Channel, the Bay of Biscay and the Mediterranean.

The White Paper *Meeting the Energy Challenge* (May 2007) announced the Government’s intention to strengthen the Renewables Obligation (RO), increasing the RO to ‘up to 20% as and when increasing amounts of renewables are deployed’ and introducing banding of the RO in order to provide differentiated support to the various renewable technologies. In this latter connection, particular mention was made of the need to bring forward offshore wind and biomass.

United States of America

The Energy Information Administration (EIA) estimates that the raw wind resource potential of the US is in excess of 3 000 GW. This estimate excludes offshore areas, areas with poor wind potential (average annual wind speeds less than 7 m/s), areas with specific legal or technical restrictions on development for wind use (such as areas with high slope, environmentally restricted areas and urban areas), and areas greater than 20 miles from existing transmission lines. However, most of the land included in this estimate is likely to be precluded from wind development for economic reasons not explicitly accounted for in the estimate, such as high land costs, rough terrain, lack of site access, aesthetic or environmental limitations, the need to upgrade or expand existing transmission capacity in order to accommodate remote wind capacity, or the need to provide energy storage or back-up generation in order to maintain grid reliability.

The American wind power industry has shown remarkable progress, increasing by an average 29% each year between 2000 and 2005. By end-2005 capacity stood at 9 149 MW and by end-2006, the American Wind Energy Association estimates that it stood at 11 603 MW. Of the states that had installed capacity at end-2005, 15 possessed more than 100 MW each. New capacity added during the year represented about 52 projects in 22 states (averaging 1.5 MW per turbine). The Department of Energy's (DOE) Wind Powering America project aims, by 2010, to have at least 30 states with more than 100 MW.

The Advanced Energy Initiative launched in February 2006 is providing the stimulus to sustain and further the progress of the US wind power industry. Whilst wind power currently only supplies approximately 0.3% of total electricity generation, the Initiative states that 'areas of good wind resources have the potential to supply up to 20% of the electricity consumption in the United States'.

The Federal production tax credit (PTC) has had a significant role in the growth of wind power. There has been a distinct correlation between the years when the US$ 0.019/kWh credit (for the first 10 years of production) was applied and the expansion of capacity. In those years when the credit lapsed (2000, 2002 and 2004) there was only a small incremental amount of capacity. The 2005 Federal Energy Policy Act (EPAct) extended the PTC to end-2007 when it is due to expire again.

Other federal incentives (depreciation deductions, loans, grants, financial and technical assistance) and state programs (renewable energy purchase mandates, green pricing, tax and investment incentives, net metering etc.) are all designed to ensure the continued growth of the industry. Looking forward, the DOE's Wind Energy Program has three aspects to its R&D: it is studying firstly, low-wind-speed turbines for deployment in the vast areas of US territory that possess less than optimal wind speeds; secondly, the areas suitable for wind installations sited, initially in shallow offshore waters and then in deeper offshore waters. It has been estimated that the US has in excess of 1 000 GW offshore potential lying between 5 and 50 nautical miles from the coastlines (including the Great Lakes), with about 810 GW in waters that are 30 m or deeper; and thirdly, the launch (in 2006) of SeaCon. The SeaCon (sea-based concept studies) initiative will concentrate on innovative technologies such as combining wind turbines with electrolysers to produce hydrogen, combining wind and hydropower technologies and the use of wind energy to provide power for municipal water and wastewater operations.

Uruguay

At the present time the country utilises its wind resource for water pumping in rural areas isolated from the electricity grid.

Uruguay plans, with international cooperation, to evaluate its wind resource potential. The project is waiting for the final approval of the GEF.

Another project, in collaboration with Spain (within the framework of a debt conversion agreement between Uruguay and Spain) and with strong public support, covers the installation of 10 MW capacity and also the measurement of the resource.

The Government passed a decree in March 2006 which as a first stage will attempt to encourage the installation of up to 20 MW of electricity generation, with up to 10 MW provided by IPPs.

13. Tidal Energy

COMMENTARY

The Tides

The tides are cyclic variations in the level of the seas and oceans. Water currents accompany these variations in sea level which in some locations, such as the Pentland Firth to the north of the Scottish mainland, can be extreme.

Small tidal 'mills' were used in Southern England and Northern France in the Middle Ages. Tidal flows in bays and estuaries offered the potential to drive cereal-grinding apparatus in areas that were too low-lying to allow the use of conventional water wheels. In the 20th century, tides were seriously re-examined as potential sources of energy to power industry and commerce.

The explanation of the existence of tides represented one of the greatest challenges to early oceanographers, mathematicians and physicists. It was not until Newton developed his theories of gravitation and the mechanics of motion that a satisfying theory emerged to explain at least some of the properties of the tides. The physics of the 'Newtonian Tidal Theory', which is sometimes referred to as 'Equilibrium Tidal Theory', gives a partial description of tidal behaviour for an abstract planet Earth entirely covered by water, and is outlined in most introductory texts on oceanography (Bearman, 1997).

Figure 13-1 The tidal bulge
Source: Bryden

There are two fundamentally different approaches to the exploitation of tidal energy. The first is to exploit the cyclic rise and fall of the sea level through entrainment and the second is to harness local tidal currents in a manner somewhat analogous to wind power.

This theory suggests the establishment of 'bulges' in the fluid surrounding the Earth as shown in Fig. 13-1.

As the Earth rotates, the two tidal 'bulges' appear to travel round the Earth at the same rate as the Earth's rotation. The Moon rotates around the Earth (actually about the centre of mass of the Earth-Moon system) every 27.3 days, in the same direction as the Earth rotates every 24 hours. Because the rotations are in the same direction, the net effect is that the period of the Earth's rotation, with respect to the Earth-Moon system, is 24 hours and 50 minutes. This explains why the tides are approximately an hour later each day.

The equilibrium theory can be extended to include the influence of the Sun. It is possible to consider the establishment of solar 'bulges' in the Earth's oceans as well as the lunar 'bulges'. When these approximately superimpose at the full moon and the new moon, large *spring tides* occur. At the half-moon stage of the lunar cycle, the solar and lunar bulges are 90^{o} out of phase and small *neap tides* occur.

In effect, the tides represent the terrestrial manifestation of the potential and kinetic energy fluxes present in the Earth-Moon-Sun system. These fluxes are complicated by the presence of continents and other landmasses, which modify the form and phase of the tidal wave. This results in some regions of the world possessing substantially higher local fluxes than others. The Bay of Fundy in Canada and the Bristol Channel between England and Wales are two particularly noteworthy examples.

Harnessing the Energy in the Tides

There are two fundamentally different approaches to the exploitation of tidal energy. The first is to exploit the cyclic rise and fall of the sea level through entrainment and the second is to harness local tidal currents in a manner somewhat analogous to wind power.

Tidal Barrage Methods

There are many places in the world in which local geography results in particularly large tidal ranges. Sites of particular interest include the Bay of Fundy in Canada, which has a mean tidal range of 10 m, the Severn Estuary between England and Wales, with a mean tidal range of 8 m and Northern France with a mean range of 7 m. A tidal-barrage power plant has indeed been operating at La Rance in Brittany since 1966 (Banal and Bichon, 1981). This plant, which is capable of generating 240 MW, incorporates a road crossing of the estuary. It has recently undergone a major ten-year refurbishment programme.

Other operational barrage sites are at Annapolis Royal in Nova Scotia (18 MW), the Bay of Kislaya, near Murmansk (400 kW) and at Jangxia Creek in the East China Sea (500 kW) (Boyle, 1996). Schemes have been proposed for the Bay of Fundy and for the Severn Estuary but have never been built.

Figure 13-2 Hypothetical tidal barrage configuration
Source: Bryden

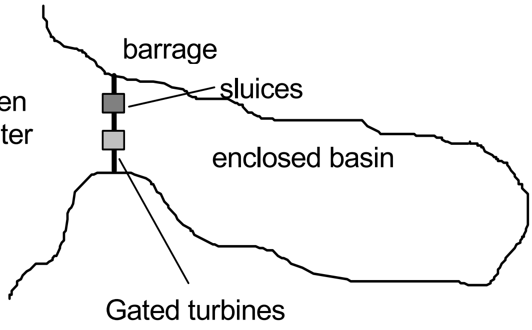
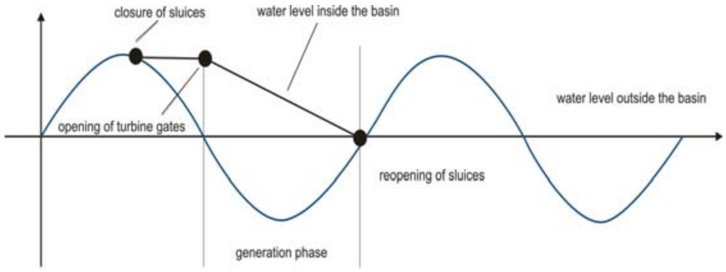


Figure 13-3 Water levels in an ebb generation scheme
Source: Bryden



Principles of Operation. Essentially the approach is always the same. An estuary or bay with a large natural tidal range is identified and then artificially enclosed with a barrier. This would typically also provide a road or rail crossing of the gap in order to maximise the economic benefit.

The electrical energy is produced by allowing water to flow from one side of the barrage, through low-head turbines, to generate electricity.

There are a variety of suggested modes of operation. These can be broken down initially into single-basin schemes and multiple-basin schemes. The simplest of these are the single-basin schemes.

Single-Basin Tidal Barrage Schemes. These schemes, as the name implies, require a single barrage across the estuary, as shown in Fig. 13-2. There are, however, three different methods of generating electricity with a single basin. All of the options involve a combination of sluices which, when open, can allow water to flow relatively freely through the barrage, and gated turbines, the gates of which can be opened to allow water to flow through the turbines to generate electricity.

Ebb Generation Mode. During the flood tide, incoming water is allowed to flow freely through sluices in the barrage. At high tide, the sluices are closed and water retained behind the barrage. When the water outside the barrage has fallen sufficiently to establish a substantial head between the basin and the open water, the basin water is allowed to flow out though low-head turbines and to generate electricity.

The system can be considered as a series of phases. Fig. 13-3 shows the periods of generation associated with stages in the tidal cycle. Typically the water will only be allowed to flow through the turbines once the head is approximately half the tidal range. This method will generate electricity for, at most, 40% of the tidal range.

Flood Generation Mode. The sluices and turbine gates are kept closed during the flood tide to allow the water level to build up outside the barrage. As with ebb generation, once a sufficient head has been established the turbine gates are opened and water can flow into the basin, generating electricity as shown in Fig. 13-4.

This approach is generally viewed as less favourable than the ebb method, as keeping a tidal basin at low tide for extended periods could have detrimental effects on the environment and on shipping. In addition, the energy produced would be less, as the surface area of a basin would be larger at high tide than at low tide, which would result in rapid reductions in the head during the early stages in the generating cycle.

Two-Way Generation. It is possible, in principle, to generate electricity in both ebb and flood. Unfortunately, computer models do

Figure 13-4 Water levels in a flood generation scheme
Source: Bryden

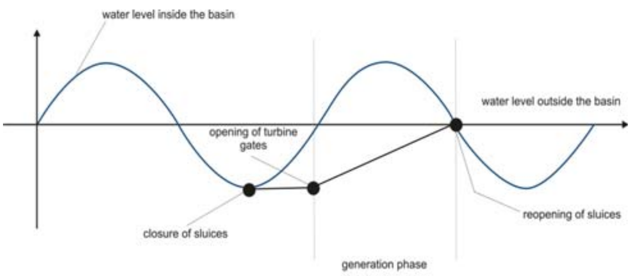
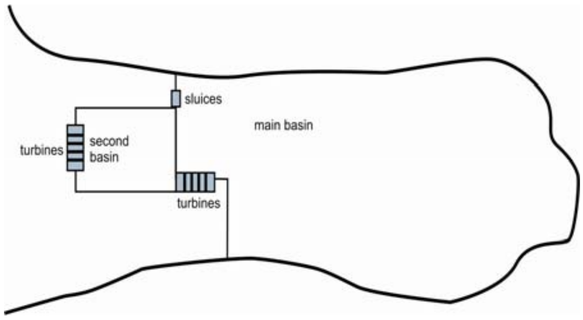


Figure 13-5 Hypothetical two-basin system
Source: Bryden



not indicate that there would be a major increase in the energy production. In addition, there would be additional expenses associated in having a requirement for either two-way turbines or a double set to handle the two-way flow. Advantages include, however, a reduced period with no generation and the peak power would be lower, allowing a reduction in the cost of the generators.

Double-Basin Systems. All single-basin systems suffer from the disadvantage that they only deliver energy during part of the tidal cycle and cannot adjust their delivery period to match the requirements of consumers. Double-basin systems, as shown schematically in Fig. 13-5, have been proposed to allow an element of storage and to give time control over power output levels.

The main basin would behave essentially like an ebb generation single-basin system. A proportion of the electricity generated during the ebb phase would be used to pump water to and from the second basin to ensure that there would always be a generation capability.

It is anticipated that multiple-basin systems are unlikely to become popular, as the efficiency of low-head turbines is likely to be too low to enable effective economic storage of energy. The overall efficiency of such low-head storage, in terms of energy out and energy in, is unlikely to exceed 30%. It is more likely that conventional pumped-storage systems will be utilised. The overall efficiency of these systems can exceed 70% which is, especially considering that this is a proven technology, likely to prove more financially attractive.

Possible Sites for Future Tidal Barrage Developments. Worldwide there is a considerable number of sites technically suitable for development, although whether the resource can be developed economically is yet to be conclusively determined (Boyle, 1996). These include, and this is not a definitive list (Fig. 13-6):

Figure 13-6 Possible sites for future tidal barrage development.
Source: Boyle

Site	Mean tidal range (m)	Barrage length (m)	Estimated annual energy production (GWh)
Severn Estuary (UK)	7.0	17 000	12 900
Solway Firth (UK)	5.5	30 000	10 050
Bay of Fundy (Canada)	11.7	8 000	11 700
Gulf of Khambhat (India)	6.1	25 000	16 400

Tidal lagoons

Tidal barrage systems are likely to cause substantial environmental change; ebb generation results in estuarial tidal flats being covered longer than in a natural estuary - this might not be acceptable; a barrage, even with locks, will cause obstruction to shipping and other maritime activity. Artificial lagoons (www.tidalelectric.com) have been proposed as alternatives to estuarial barrages. Electricity

Many engineers and developers now favour the use of technology which will utilise the kinetic energy in flowing tidal currents.

would be generated using sluices and gated turbines in the same manner as 'conventional' barrage schemes.

The principal advantage of a tidal lagoon is that the coastline, including the intertidal zone, would be largely unaffected. Careful design of the lagoon could also ensure that shipping routes would be unaffected. A much longer barrage would, however, be required for the same surface area of entrainment. Some preliminary studies do suggest, however, that in suitable locations the costs might be competitive with other sources of renewable energy. However, there has not yet been any in-depth peer-reviewed assessment of the tidal lagoon concept, so estimates of economics, energy potential and environmental impact should be treated with caution.

The Severn Estuary, which lies between England and Wales, and the mouth of the Yalu River, China have both been suggested as potential locations for lagoon-style development.

Tidal Current Technology

Principles and History. Presently the development of tidal barrage schemes has been limited. This has been partly a result of the very large capital costs of such systems associated with the long construction times and fear of environmental impact.

Many engineers and developers now favour the use of technology which will utilise the kinetic energy in flowing tidal currents. The most thoroughly documented early attempt to prove the practicality of tidal current power was conducted in the early 1990s in the waters of Loch Linnhe in the West Highlands of Scotland (www.itpower.co.uk/researchdevelopment.htm). This scheme used a turbine held mid-water by cables, which stretched from a sea-bed anchor to a floating barge.

The mid to late 1990s was primarily a time of planning and development as far as tidal current power was concerned, and it was not until the beginning of the 21st century that further systems became ready to test. In 2000 a large vertical-axis floating device (the Enermar project [www.pontediarchimede.com]) was tested in the Strait of Messina between Sicily and the Italian mainland. Marine Current Turbines Ltd (www.marineturbines.com) of Bristol, England, has been demonstrating a large pillar-mounted prototype system called Seaflow in the Bristol Channel, which lies between England and Wales. Fig. 13-7 shows the Seaflow system with its nacelle raised into the 'maintenance position'. It is intended that the same company will install a further large prototype system, SeaGen, in Strangford Narrows in Northern Ireland, probably in late-summer 2007 (Fig. 13-8). Although conceptually similar to Seaflow, it would be equipped with two rotors and have a rated capacity of 1.2MW.

In Norway, the Hammerfest Strøm system (www.tidevannsenergi.com) demonstrated that pillar-mounted horizontal-axis systems can operate in a fjord environment. In the USA the first of an array of tidal turbines were installed in

Figure 13-7 Seaflow with the nacelle raised
Source: Marine Current Turbines

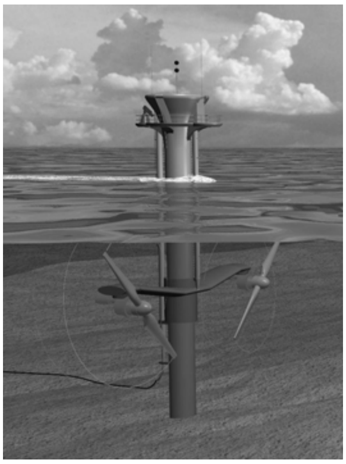
December 2006 in New York's East River (www.verdantpower.com). Once fully operational this should be the world's first installed array of tidal devices.

In 2007, The European Marine Energy Centre (EMEC) (www.emec.org.uk), which was established in 2004 to allow the testing of full-scale marine energy technology in a robust and transparent manner, became fully equipped for the testing of tidal, as well as wave energy, technology. The tidal test berths are located off the south-western tip of the island of Eday, in an area known as the Fall of Warness.

The facility offers five tidal test berths at depths ranging from 25 m to 50 m in an area 2 km across and approximately 3.5 km in length. Each berth has a dedicated cable connecting back to the local grid. The first tidal device (www.openhydro.com) was installed at the end of 2006. This is operated by the OpenHydro Group and is a novel annular-turbine system held by twin vertical pillars. The system can be seen in its maintenance position in Fig. 13.-9.

The physics of the conversion of energy from tidal currents is superficially very similar, in principle, to the conversion of kinetic energy in the wind. Many of the proposed devices have therefore an inevitable, though superficial, resemblance to wind turbines. There is, however, no total agreement on the form and geometry of the conversion technology itself. Wind-power systems are almost entirely

Figure 13-8 Artist's impression of SeaGen
Source: Marine Current Turbines



horizontal-axis rotating turbines. In these systems the axis of rotation is parallel to the direction of the current flow. Many developers favour this geometry for tidal conversion. Vertical-axis systems, in which the axis of rotation is perpendicular to the direction of current flow, have not been rejected. It is of interest to note that Enermar used a novel Kobold vertical-axis turbine.

Figure 13-9 The OpenHydro system installed at EMEC
Source: OpenHydro

The environmental drag forces on any tidal-current energy-conversion system are very large, when compared with wind turbines of the same capacity. This poses additional challenges to the designer. Designs exist for devices which are rigidly attached to the seabed or are suspended from floating barges, such as the early Loch Linnhe device. It is generally accepted that fixed systems will be most applicable to shallow-water sites and moored systems for deep water. There may be exceptions to this, however.

Energy Available in Tidal Currents. The superficial similarity between the kinetic energy flux in tidal currents and energy available from the wind encouraged the design of technology with more than a passing resemblance to wind turbines. Early assessments of the available energy also, rather unfortunately, encouraged the consideration of resource availability in terms of the kinetic energy flux alone, without taking due account of the nature of the free surface between the sea water and the atmosphere, the frictional interactions between the flowing water and the flow boundaries, or the complex turbulent nature of the flow.

It is very tempting to consider only the kinetic energy flux in moving water when assessing available energy. This can be very easily calculated for water passing through a cross section by using equation 1

$$P_K = \tfrac{1}{2}\rho\int_A U^3 dA \qquad \text{(Watts)} \qquad (1)$$

where:

ρ is the density of water (kgm^{-3})

U is the component of flow velocity perpendicular to the section area (ms^{-1}), which is normally a function of position within the cross section.

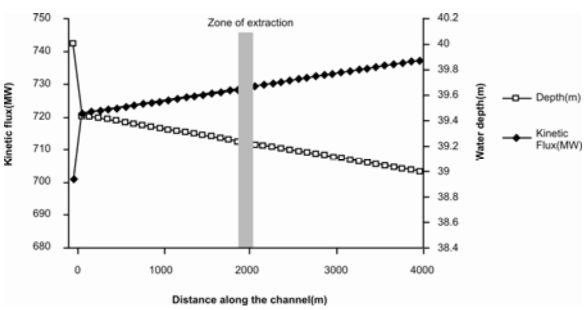
A is the cross section area (m^2)

Further analysis rapidly reveals that, although the value of the kinetic energy flux can suggest the presence of extractable energy, the actual potential of a site to deliver energy is a more complex relationship involving understanding of the nature of the total flow environment.

Fig. 13-10 shows the expected kinetic energy flux in a simple, static head driven channel (Bryden, Grinsted and Melville, 2005) of length 4 km, width 500 m, an inlet depth of 40 m and an outlet depth of 39 m. The kinetic energy flux increases along the channel. The figure clearly shows a head drop immediately downstream of the inlet, resulting from acceleration of the flow from stationary in the inlet ocean, resulting in a sharp head drop.

Figure 13-10 Kinetic flux and depth variation in a simple channel driven only by head difference.

Source: Bryden, Grinsted and Melville



It is interesting to speculate on the influence of extracting energy at the mid-point of the channel. Fig. 13-11 shows, for the same channel, the influence of extracting energy equivalent to 25% of the kinetic flux in the

Figure 13-11 Influence of artificial energy extraction on the water depth and the kinetic energy flux
Source: Bryden, Grinsted and Melville

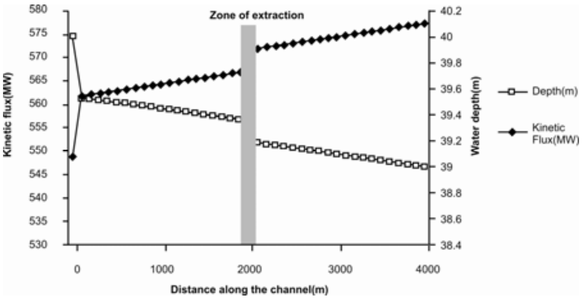
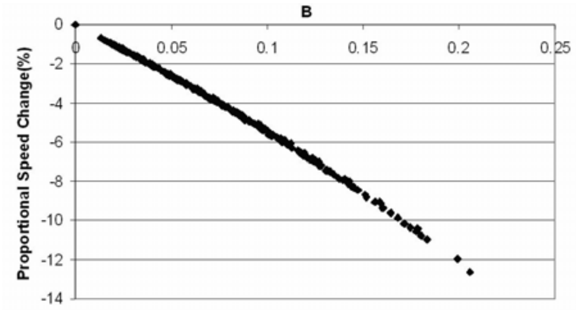


Figure 13-12 Channel sensitivity expressed as a function of the non-dimensional parameter B
Source: Bryden, Couch, Owen and Melville



undisturbed channel, with the output expressed in terms of channel depth and kinetic flux. The kinetic energy flux in the channel is actually higher downstream from the energy extraction than upstream. If the available energy is only considered in terms of kinetic flux, this would be a bewildering result in which energy appears to be coming from nothing and contradicting the conservation of energy. This is not, of course, the case.

At least part of the mystery can be solved by comparing Figs. 13-10 and 13-11. The kinetic flux in the exploited scenario is substantially less than that in the unexploited case.

It can be demonstrated (Bryden, Couch, Owen, Melville) that many of the properties of the simple channel model can be expressed in terms of a simple parameter given in equation 2, which appears to govern at least some of a channel's response to energy extraction.

$$B = \left(\frac{f}{1 + \frac{2gLn^2}{R^{\frac{4}{3}}}} \right) \qquad (2)$$

where:

f is the ratio of energy extraction to the actual kinetic flux in a channel
L is the channel length (m)
g is the acceleration due to gravity (ms^{-2})
n is the Manning Roughness Coefficient
R is the hydraulic radius (m)

Fig. 13-12 shows the result of a sensitivity study into the influence of changes in the channel length, width, depth and roughness, expressed in terms of the parameter B.

This implies that the parameter, B, at least in terms of the simple channel model, appears to offer the prospect of a simple assessment of channel sensitivity to energy extraction.

Further analysis (Bryden and Couch, 2007) of the nature of energy extraction from simple channels can show that it is possible to extract more energy than the total kinetic flux. Equation 3 shows the maximum energy extraction, expressed as a function of channel parameters.

$$P_{opt} = \tfrac{1}{2}\rho A U_0^3 \frac{2}{3\sqrt{3}} \left[1 + \frac{2gn^2L}{R^{\left(\frac{4}{3}\right)}} \right] \qquad (3)$$

This takes the form of the kinetic flux multiplied by a term influenced by channel parameters. It is obvious from this equation that knowledge of the undisturbed kinetic energy flux is necessary for the determination of the potential for energy extraction, but that it is also necessary to know additional facts about the geography of the site.The simple channel models used to generate equations 1 to 3 are recognised as abstractions and that real tidal environmental flows are far more complex than such simple approaches can fully describe. Even models of more complex channel (Garrett and Cummins, 2005) might not be sufficient, as many energetic tidal regions are multiply connected with inter island channels in a complex geography.

Figure 13-13 Numerical model of flow in the immediate vicinity of a tidal current device
Source: Bryden, Couch and Harrison

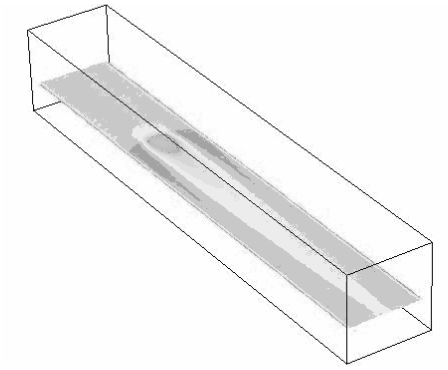
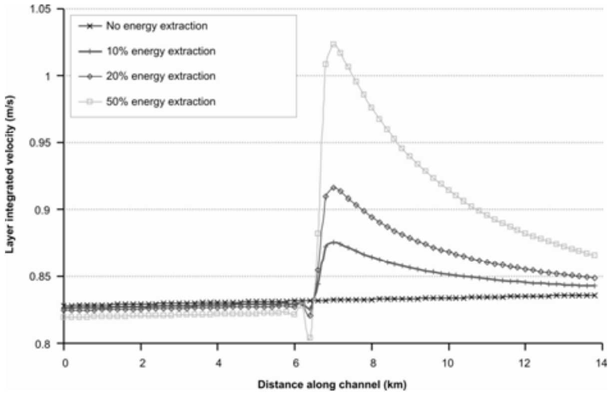


Figure 13-14 Predicted flow disruption close to the sea bed
Source: Bryden, Couch and Harrison



Progress is, however, now well advanced in the understanding of complex flows in three dimensions and it is now possible (Couch and Bryden) to assess the impact of energy extraction, even in multiply connected flow domains typical of real high energy tidal zones. Even issues associated with environmental disruption from energy extraction, such as localised flow distortion shown in Fig. 13-13 and disruption close to the sea bed as shown in Fig. 13-14, are being addressed and, with this increased knowledge, uncertainties about the resource potential for tidal currents and environmental constraints are potentially quantifiable.

Development Options for Tidal Currents. The environment that tidal devices will operate in is very different from that experienced by wind turbines, and there are some rather difficult problems associated with installation, survivability and maintenance which need to be solved before true commercial exploitation can be achieved. Proposed development options often involve the use of dedicated installation and maintenance vessels, which suggests that tidal currents might only be economically developed in large sites, where major developments can be installed, justifying the use of an expensive infrastructure.

Small sites could perhaps be developed, however, using technology which can be installed and maintained using less expensive techniques. The Sea Snail, which has been developed by the Robert Gordon University, which can be installed using a small sea-going tug, could be an option. This sea-bed located device, which is shown in Fig. 13-15, is held to the sea bed using variable-position hydrofoils which generate substantial down force, thus reducing the need to use substantial ballast.

Figure 13-15 Launch preparations for the Sea Snail in Orkney, Scotland.
Source: Bryden

Many industrial, commercial and public bodies have suggested that there is a high degree of synergy between the development of a tidal-current generation industry and the offshore oil and gas industry. This offers the intriguing prospect of a new renewable industry developing in partnership with the petroleum industry and could, perhaps, result in accelerated development, as a result of the availability of expertise and technology, which would otherwise have to be developed from scratch.

Unlike the wind, tides are essentially predictable, as they derive from astronomic processes. Wind-power systems are dependent upon random atmospheric processes. This results in it being difficult to integrate large wind-power developments into strategic electricity distribution networks. The predictability of the tides will make this integration much easier.

Although prototype tidal-current devices are now available and have mostly proved successful in their operation, there are still issues requiring resolution before the resource can be fully exploited. With the exception of the New York East River development, knowledge of the performance of devices in arrays is somewhat limited, although theoretical models are at last becoming available. It is also becoming obvious that turbulence levels in high-energy tidal flows can be considerable. Turbulent amplitudes exceeding 30% of the time-averaged flows have been measured and this will prove challenging to systems designers. Similarly there is an ongoing need for enhanced understanding of the behaviour of tidal-current devices in the presence of incident waves. These gaps in understanding should not, however, prevent ongoing deployment of pre-commercial, or even early-stage commercial technology, provided that technology developers are aware of the design constraints that knowledge gaps impose and recognise that they themselves are part of the research process. This will ultimately allow efficient technology development and hence allow cost-effective exploitation of the tidal-current resource.

The Future of Tidal Power

The high capital costs associated with tidal barrage systems are likely to restrict development of this resource in the near future. The developments that do proceed in the early 21st century will most likely be associated with road and rail crossings to maximise the economic benefit. There is, however, more interest in entrainment systems now than at any time in the past 20 years and it is increasingly likely that new barrage and lagoon developments will be seen, especially in those locations which offer combination with transport infrastructure. In a future in which energy costs are likely to rise and assuming that low-cost nuclear fusion or other long-term alternatives do not make an unexpectedly early arrival, then tidal barrage schemes could prove to be a major provider of strategic energy in the late 21st century and beyond. The technology for tidal barrage systems is already available and there is no doubt, given the experience at La Rance, that the resource is substantial and available.

Full-scale prototype tidal-current systems are now being deployed. If these schemes continue to prove successful, then the first truly commercial developments will appear in the first decade of the 21st century. Tidal-current systems may not yet have the strategic potential of barrage systems but, in the short term at least, they do offer opportunities for supplying energy in rural, coastal and island communities. In the longer term, massive sites such as the Pentland Firth could become strategically important.

Ian Bryden
Institute for Energy Systems,
The University of Edinburgh, Scotland

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COUNTRY NOTES

The Country Notes on Tidal Energy have been compiled by the Editors, drawing upon a wide range of sources. National, international, governmental publications/web sites have all been consulted.

Canada

Embayments at the head of the Bay of Fundy between the maritime provinces of New Brunswick and Nova Scotia have some of the largest tidal ranges in the world. The most promising prospects for tidal power have centred on two sites in this region: the Cumberland Basin (an arm of Chignecto Bay) and the Minas Basin (both at the head of the Bay of Fundy). However, the only commissioned tidal power plant is located at Annapolis Royal, further down the Bay in Nova Scotia. The 20 MW plant came into operation in 1984: the barrage was primarily built to demonstrate a large-diameter rim-generator turbine. Annapolis uses the largest Straflo turbine in the world to produce more than 30 million kWh per year.

In view of the large tidal energy resource of the two basins, estimated to be 17 TWh per year, different options for energy storage and integration with the river hydro system have been explored. Following an application for funding in late-2006, Nova Scotia Power announced in January 2007 that the company planned to establish a tidal stream demonstration project in the Minas Passage, Bay of Fundy. OpenHydro of Ireland has been selected to provide the tidal turbine which once deployed, will be the world's largest in-stream tidal generating unit integrated into an electricity grid. Nova Scotia Power plans to develop large tidal farms in the Bay following a successful installation of the demonstration plant.

China

The south-eastern coastal areas of Zhejiang, Fujian and Guangdong Provinces are considered to have substantial potential for tidal energy. China's utilisation of tidal energy with modern technologies began in 1956: several small-scale tidal plants were built for pumping irrigation water. Thereafter tidal energy began to be used for power generation. Starting in 1958, 40 small tidal plants (total capacity 12 kW) were built for the purpose of generating electricity. These were supplemented from around 1980 by much larger stations, of which the 3.2 MW Jiangxia and the 1.3 MW Xingfuyang schemes were the largest. The majority of the early plants have been decommissioned for a variety of reasons, including design faults, incorrect location, etc. Currently there are seven tidal power stations (plus one tide flood station) with a total capacity of 11 MW.

Since the end of the 1970s emphasis has been placed on optimising the operations of existing plants to improve their performance. Additionally, a feasibility study for a 10 MW level intermediate experimental tidal power station has been undertaken.

It was announced in November 2006 that China had signed a joint venture with the Italian engineering company Ponte di Archimede International for the application of its patented Kobold turbine to a site in the Strait of Jintang, in the Zoushan Archipelago.

France

Relatively few tidal power plants have been constructed in the modern era. Of these, the first and largest is the 240 MW barrage on the Rance estuary in northern Brittany. The 0.8 km long dam also serves as a highway bridge linking St. Malo and Dinard. The barrage was built as a full-scale demonstration scheme between 1961 and 1966 and has now completed 40 years of successful commercial operation. Annual generation is some 640 million kWh.

Originally the barrage was designed to generate on both flood and ebb tides; however, this mode of operation proved to be only partially successful. The barrage is now operated almost exclusively on ebb tides, although two-way generation is periodically instigated at high spring tides.

In 1988 the plant became fully automated, requiring the integration of complex operational cycles imposed by variable heads, and the necessity for continuous regulation of the turbines to optimise energy conversion. A 10 year programme for refurbishing its 24 turbines was begun in 1996, on the plant's 30th anniversary.

Despite its successful operation, no further tidal energy plants are planned for France, which is now dominated by generation from nuclear stations.

India

The main potential sites for tidal power generation are the Gulf of Kutch and the Gulf of Khambhat (Cambay), both in the western state of Gujarat, and the Gangetic delta in the Sundarbans area of West Bengal, in eastern India.

The tidal ranges of the Gulf of Kutch and the Gulf of Khambhat are 5 and 6 m, the theoretical capacities 900 and 7 000 MW, and the estimated annual output approximately 1.6 and 16.4 TWh, all respectively.

The West Bengal Renewable Energy Development Agency (WBREDA) prepared a project report (on behalf of the Ministry of Non-Conventional Energy Sources) for a 3.65 MW demonstration tidal power plant at Durgaduani Creek in the Sundarbans. This was followed by an environmental impact assessment study. In February 2007 the WBREDA stated that it had engaged the National Hydroelectric Power Corporation to implement the Rs 400 million (approximately US$ 10 million) project on a turnkey basis, with work likely to begin in the near future.

Korea (Republic)

It was announced in mid-2005 that the country's first tidal power plant was to be constructed at Sihwa-Lake, 25 km southwest of Seoul on the western coast of the Peninsula, with the Korea Water Resources Corporation acting as project developer.

The artificial lake was created between 1987 and 1994 to provide water for agricultural purposes. A dam curtailing the tidal currents was constructed but the quality of the water deteriorated, becoming heavily polluted following a rise in local industry and a consequent increase in factory wastes.

A sophisticated plan has been formulated whereby the power plant will utilise the head between high tide on one side and the level of the lake on the other. The scheme will not only provide generation of electricity but also environmental improvements and tourist attractions. The Korean Energy Economics Institute reported in April 2007 that construction of the 254 MW plant will be completed by July 2008 and that annual power generation is expected to be in the region of 550 GWh. On completion Sihwa-Lake will be the world's largest tidal energy plant.

In May 2007 the city of Incheon announced that it had signed an MOU with Korea Midland Power Co. and Daewoo Engineering and Construction to build the Ganghwa tidal plant. At 812 MW, the 32-generator plant would overtake the Sihwa-Lake project to be the world's largest tidal scheme when the plant becomes operational – planned for 2015. A 7.8 km long dam will connect four islands: Ganghwa, Gyodong, Seokmo and Seogeom.

Norway

Installation of a 300 kW prototype tidal power plant began in September 2003 in the Kval Sound in the far north of Norway. The world's first grid-connected offshore underwater turbine is located at Kvalsundet, close to Hammerfest. The plan is to increase the size of the prototype to 700 kW, thereby commercialising the project prior to the installation of 20 such turbines.

A 1 MW floating tidal power plant – the MORILD demonstration project - is planned for deployment in 2007-2008 near Tromsø. Following a period of testing it is hoped that commercialisation will follow.

Russian Federation

Design studies for tidal power development have been conducted in Russia since the 1930s. As part of this work, a small pilot plant with a capacity of 400 kW was constructed in Kislaya Bay on the Barents Sea and commissioned in 1968. The location has now become an experimental site for testing new tidal power technologies.

Early in 2007, GidroOGK, a subsidiary of the Russian electric utility, Unified Energy Systems (UES), began the installation of a 1.5 MW orthogonal turbine alongside the original Kislaya Bay tidal facility. The experimental turbines will be thoroughly tested as part of a pilot project to assist in the design of large-scale tidal power plants.

There are currently two ambitious projects for TPPs in the Federation:

Mezenski Bay (on the White Sea, in northern Russia): proposed capacity 15 GW, annual output 40 TWh;

Tugurki Bay (on the Sea of Okhotsk in the Russian Far East): 7.98 GW, 20 TWh annual output.

If the 1.5 MW experimental installation at the Barents Sea location proves successful, UES intends to embark on a programme for constructing giant-size TPPs such as those projected.

United Kingdom

The large tidal range along the west coasts of England and Wales provides some of the most favourable conditions in the world for the utilisation of tidal power. If all reasonably exploitable estuaries were utilised, annual generation of electricity from tidal power plants would be some 50 TWh, equivalent to about 15% of current UK electricity consumption.

Of six identified sites with mean tidal ranges of 5.2-7.0 m, feasibility studies have been completed for two large schemes: the Severn estuary (8 640 MW) and the Mersey estuary (700 MW) and for smaller schemes on the estuaries of the Duddon (100 MW), Wyre (64 MW), Conwy (33 MW) and Loughor (5 MW). A governmental programme on tidal energy (1978-1994) concluded that given the combination of high capital costs, lengthy construction periods and relatively low load factor (21-24%), none of these schemes was regarded as financially attractive.

Plans have often been formulated for the development of a Severn estuary scheme but to date nothing has ensued, largely owing to ecological concerns.

In recent years much work has been undertaken on the furtherance of tidal stream technology. The Stingray prototype was installed in Yell Sound in the Shetland Islands in September 2002. The 150 kW plant was successfully tested twice and a 5 MW tidal farm was planned for 2005-2007. However, during 2005 the project was suspended, as it was felt to be commercially unviable.

Following preliminary development work during 1999-2002, Phase 1 Seaflow, (2002-2006), the first commercial-scale tidal stream project in the UK, began in mid-2003. An experimental 300 kW turbine was installed 3 km offshore from Lynmouth, Devon by Marine Current Turbines (MCT). Although capable of grid connection, it has used a dump load during the testing period. A large amount of data will have been gathered by the time of decommissioning ($3^{rd}/4^{th}$ quarter 2007 / early 2008).

Building on the experience of Seaflow, Phase 2 SeaGen, (2004-2007), is intended to cover the development of a twin-rotor 1.2 MW grid-connected Commercial Demonstrator. In December 2005 MCT received permission to install a 1 MW grid-connected plant in Strangford Narrows, Northern Ireland. Installation, due to begin in late-2006, was postponed and is now likely to occur in the second half of 2007, taking some six months to complete.

Again, building on the experience of SeaGen, Phase 3 SeaGen *2* is a plan to develop about 10 tidal farms of 5-10 MW capacity. The farms, in part self-financing through the sale of electricity, would ultimately be owned by the utility companies with the power fed to the UK grid. Concurrently, SeaGen *2*- type turbines could be used as demonstrator projects in North America (on both Atlantic and Pacific coasts of Canada and the USA), southeast Asia and possibly New Zealand.

A plan for a 10 MW grid-connected tidal farm - the Lynmouth SeaGen Array - has now been 'put on the back burner' in favour of a tidal farm off the coast of Anglesey. In mid-2006, the company announced a feasibility study for 7 units (SeaGens) as a grid-connected tidal farm totalling 10 MW. The site has the potential to be expanded in further phases, possibly up to 100 MW. An Environmental Impact Assessment (EIA) is currently being conducted but once the necessary approvals are granted, an array could be operational by 2009, providing electricity for 4 000 – 6 500 homes on the island.

Study has shown that the island of Alderney has tidal ranges ideally suited to being harnessed. It has been estimated that the island's coastline has a power potential of between 750 MW and 3 GW. In March 2007 it was announced that Alderney Renewable Energy Ltd (ARE) and the OpenHydro Group, an Irish energy technology company, had signed an agreement to carry out the testing and deployment of the Channel Islands' first tidal turbines. Deployment is expected to take place in 2008/2009. As well as providing electricity for the local market, one major aim of a tidal scheme would be to export power to the French national grid.

The European Marine Energy Centre (EMEC) announced in December 2006 that OpenHydro had successfully completed the installation of a tidal turbine. EMEC's Tidal Test Facility is located off the south-western coast of the island of Eday, Orkney. Testing of the system will be undertaken during 2007. The extensive infrastructure will be connected to the local electricity grid and test results sent directly to EMEC's data centre in Stromness.

In February 2007, it was announced that the Scottish Parliament had awarded OpenHydro grant support towards the deployment of a second turbine at the EMEC.

The Government White Paper *Meeting the Energy Challenge* (May 2007) mentions that the Sustainable Development Commission is carrying out a major study, examining the issues relating to harnessing tidal power in the UK. A wide range of locations and technologies will be taken into consideration, including the possibility of utilising the tidal potential of the Severn Estuary. The report is expected to be published in September 2007.

United States of America

Prior to submitting a licence application to the Federal Energy Regulatory Commission (FERC), Verdant Power is carrying out an 18-month study of the environmental impact and operational performance of an array of six of its Kinetic Hydro Power Systems (KHPS) in the East Channel of the East River in New York City. The Roosevelt Island Tidal Energy Project (RITE) is being carried out with financial support from the New York State Energy Research and Development Authority. If the tests prove successful and a licence is granted, it is planned to scale-up the installation to 300 turbines, with a total generating capacity of up to 10 MW.

14. Wave Energy

COMMENTARY

COMMENTARY

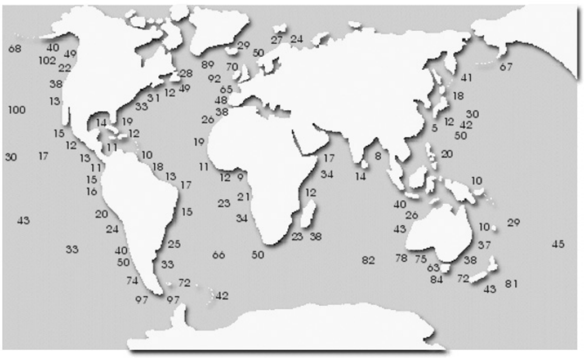
Introduction

The first serious study of wave energy took place in the 1970s and early 1980s when several governments undertook national R&D programmes as a response to the emerging oil crises. Since the late 1990s a number of small companies have tried to develop and commercialise a range of different wave energy technologies as a non-polluting source of energy, which has resulted in a number of full-size devices being deployed in the sea. In some countries, these initiatives have been accompanied by government-funded activities, as well as developments in international organisations such as the European Commission and the International Energy Agency.

The Resource

Wave energy can be considered as a concentrated form of solar energy, where winds generated by the differential heating of the earth pass over open bodies of water, transferring some of their energy to form waves. The amount of energy transferred and hence the size of the resulting waves, depends on the wind speed, the length of time for which the wind blows and the distance over which it blows (the 'fetch'). In this way, the original solar power levels of typically ~ 100 W/m^2 can be transformed into waves with power levels of over 1 000 kW per metre of wave crest length.

Figure 14-1 Average annual wave power levels as kW/m of wave front
Source: Ocean Power Delivery



Wave energy can be considered as a concentrated form of solar energy, where winds generated by the differential heating of the earth pass over open bodies of water, transferring some of their energy to form waves.

Waves lying within or close to the areas where they are generated (storm waves) produce a complex, irregular sea. These waves will continue to travel in the direction of their formation even after the wind dies down. In deep water, waves lose energy only slowly, so they can travel out of the storm areas with minimal loss of energy as regular, smooth waves or 'swell' and this can persist at great distances from the point of origin. Therefore, coasts with exposure to the prevailing wind direction and long fetches tend to have the most energetic wave climates, such as the western coasts of the Americas, Europe, Southern Africa and Australia/New Zealand, as shown in Fig. 14-1.

The global wave power resource in deep water (i.e. 100 m or more) is estimated to be ~ 1–10 TW (Panicker, 1976). As the waves move to shallower waters they lose energy, but detailed variation of sea-bed topography can lead to the focusing of wave energy in concentrated regions near the shoreline, called 'hot spots'. The economically exploitable resource varies from 140-750 TWh/yr for current designs of devices when fully mature (Wavenet, 2003) and could rise as high as 2 000 TWh/yr (Thorpe, 1999), if the potential improvements to existing devices are realised.

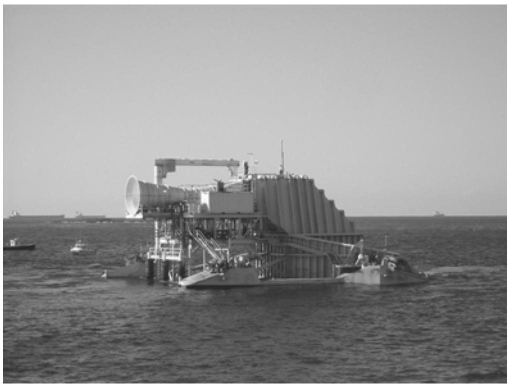
Wave Energy Technologies

There are several significant reviews of wave energy (Thorpe, 1999; Clément, et al., 2002; Brooke, 2003; IEA, 2003; Wavenet, 2003; Previsic, et al., 2004). These show that many wave energy devices are at the R&D stage, with only a small range of devices having been tested at large scale or deployed in the oceans. This slow rate of progress is because wave energy devices face a number of design challenges:

- *Design Waves*. To operate its mechanical and electrical plant efficiently, a wave energy device must be rated for wave power levels that occur much of the time (e.g. in the UK this would be 30-70 kW/m). However, the device also has to withstand extreme waves that occur only rarely and these could have power levels in excess of 2 000 kW/m. This poses a significant challenge, because it is the lower power levels of the commonly-occurring waves that produce the normal output of the device (and hence the revenue), while the capital cost is driven by the civil structure that is designed to withstand the high power levels of the extreme waves.
- *Variability of Wave Power Levels.* Waves vary in height and period from one wave to the next and from storm to calm conditions. While the gross average wave power levels can be predicted in advance, this inherent variability has to be converted to a smooth electrical output if it is to be accepted by the local electrical utility. This usually necessitates some form of energy storage.

Figure 14-2 Shoreline OWC – the LIMPET
Source: Wavegen

Figure 14-3 Nearshore OWC
Source: Energetech

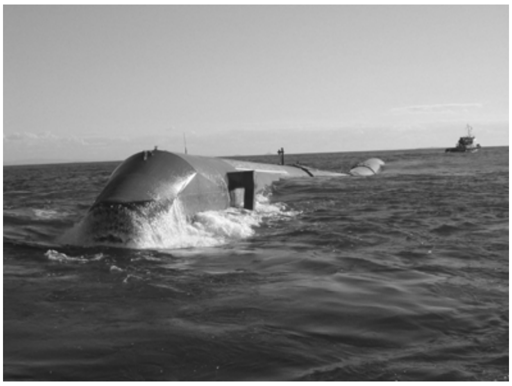


- *Variability in Wave Direction.* Normally, offshore waves travel towards a wave energy device from a range of directions, so a wave energy device has to be able to cope with this variability either by having compliant moorings (which allow the device to point into the waves) or by being symmetrical. Another approach is to place the wave energy device close to the shore, because waves are refracted as they approach a coastline, so that most end up travelling at right angles to the shoreline.
- *Wave Movement.* The relatively slow oscillation of waves (typically at ~ 0.1 Hz) has to be transformed into a unidirectional output that can turn electrical generators at hundreds of rpm, which requires a gearing mechanism or the use of an intermediate energy transfer medium.

Different devices have different solutions to these challenges, as exemplified by just four of the main types of device deployed at large scale over the past few years:

- *Oscillating Water Column.* The Oscillating Water Column **(**OWC) comprises a partially submerged structure forming an air chamber, with an underwater aperture. This chamber encloses a volume of air, which is compressed as the incident wave makes the free surface of the water rise inside the chamber. The compressed air can escape through an aperture above the water column which leads to a turbine and generator. As the water inside falls, the air pressure is reduced and air is drawn back through the turbine. Both conventional (i.e. unidirectional) and self-rectifying air turbines have been proposed. Even with this commonality of operating principles, the examples of oscillating water column actually deployed vary considerably from the bottom-standing, shoreline-based concrete device developed by Wavegen (2007) in Scotland (Fig. 14-2) to the tethered, nearshore steel device deployed by Energetech (2007) in Australia (Fig 14-3).
- *The Pelamis.* The Pelamis is a floating device comprised of a series of cylindrical hollow steel segments that are connected to each other by hinged joints. The device is approximately 120 m long, 3.5 m in diameter and is loosely moored in water depths of ~ 50 m so that it points into the waves (Fig. 14-4). As waves run down the length of the device, the segments move with respect to each other and actuate hydraulic cylinders incorporated in the joints to pump oil to drive a hydraulic motor/generator via an energy-smoothing system. The device has been deployed in Scotland and a small scheme of three

Figure 14-4 The Pelamis Wave Energy Converter
Source: Ocean Power Delivery



devices is currently being deployed in Portugal (OPD, 2007).

- *The Wave Dragon.* This device uses a pair of large curved reflectors to gather waves into the central receiving part, where they flow up a ramp and over the top into a raised reservoir, from which the water is allowed to return to the sea via a number of low-head turbines. A quarter-scale prototype (58 m wide x 33 m long) rated at 20 kW has been deployed in a Danish inlet (Fig. 14.5) and a full-size device (estimated to have a generation capacity of ~ 4 MW) is being constructed for a site in Wales (Wave Dragon, 2007).
- *The Archimedes Wave Swing.* This consists of a buoyant cylindrical, air-filled chamber (the 'Floater') that can move vertically with respect to the cylindrical 'Basement', which is fixed to the sea bed. As a wave passes over the top of the device, it alternatively pressurises and depressurises the air within the Floater, changing its buoyancy, which causes the Floater to move up and down with respect to the Basement (AWS, 2007). This relative motion is used to produce energy, using a linear electrical generator.
A 2 MW Pilot scheme has been deployed and tested in Portugal (Fig. 14-6).

Figure 14-5 The Wave Dragon
Source: Wave Dragon

Figure 14-6 The Archimedes Wave Swing
Source: AWS

This range of devices, plus the many others that are currently being developed, indicate that wave energy is currently an immature technology, without a clear consensus on which are eventually likely to prove the successful devices.

This state of affairs is compounded by a significant non-technical challenge faced by wave energy developers, namely that the technologies are being developed by small companies, with a total investment of US$ 5-10 million in each company (one or two companies have exceeded this, many are below this range). This is a small amount on which to research, develop and deploy a completely new technology, thereby increasing the chances of failures in early prototypes, which could lead to a loss in confidence in this sector.

Wave energy is currently an immature technology, without a clear consensus on which are eventually likely to prove the successful devices.

Additionally, in many countries there is a high cost associated with obtaining licences, gaining permits and carrying out environmental impact assessments, which small companies find difficult to meet. Moreover, once deployed in free energy markets, wave energy has to compete with established renewable energy technologies that have benefited from billions of dollars of cumulative investment.

It is promising to note that several common themes are starting to emerge from different developers, e.g.

- overtopping devices (e.g. the Wave Dragon, Seawave Slot-Cone Generator and Wave Plane use this capture mechanism);
- bottom-mounted hinged plates moving back and forth and operating hydraulic pumps (e.g. the BioWAVE, Oyster and WaveRoller);
- Oscillating Water Columns (e.g. Energetech OWC, Superbuoy and Wavegen's LIMPET).

However, it is disheartening to see several new developers needlessly 'reinventing the wheel' and repeating mistakes in device design that were first made decades ago.

Environmental Aspects

Most studies (e.g. Wavenet, 2003) have concluded that the environmental impact of wave energy schemes is likely to be low, provided developers show sensitivity when selecting sites for deployment and that all the key stakeholders are consulted.

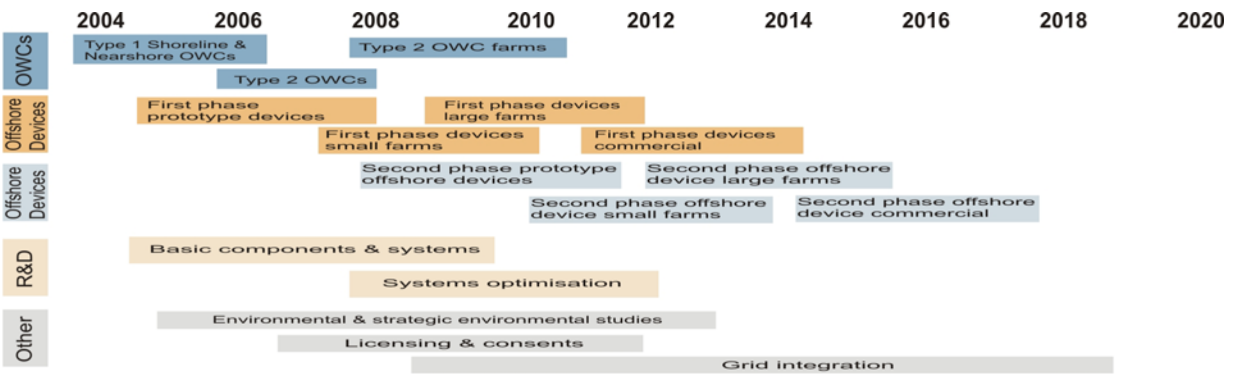
In addition, several wave energy developers are seeking to use their technology for producing potable water by reverse osmosis (RO), thereby helping to address a major environmental crisis – the lack of drinking water for many millions of people. The fact that the vast majority of the world's population live within 30 km of the coast makes wave energy a suitable technology for providing water close to where it will be consumed.

The Prospects for Wave Energy

In addition to the large size of the resource and the lack of associated greenhouse gas emissions, wave energy has two important advantages:

- outside the tropics, storms are usually more intense and frequent during winter, which results in wave power levels being higher in that season. Therefore wave energy provides good seasonal load-following for those regions where peak electricity demand is produced by winter heating and lighting requirements (e.g.,

Figure 14-7 Roadmap for wave energy
Source: Thorpe



northern Europe, western Canada and north-west USA).

- wave energy is predictable for one to two days ahead, because satellites can measure waves out in the ocean that will later impact on devices around the coast. This predictability will allow for less spinning reserve than is often required to support more intermittent renewable energy sources.

The generating costs of the first wave energy devices are high (≥ US$ 300/kWh), because all the high fixed costs associated with a wave energy scheme (permits, surveys, grid connection, R&D) are defrayed against the output of a single device. In addition, prototype devices are, by definition, immature, so they will perform less well than follow-on schemes and savings in costs through design optimisation and mass production cannot be achieved on the first devices. The UK-based Carbon Trust (2006) estimated a central range of generating costs between 22 and 25 pence/kWh (~ US$ 0.44 and 0.50/kWh) for a typical project financed commercially. However, the same study predicted that the generating costs could be significantly reduced in future to a cost comparable with other renewable energy sources, but that this would require some form of subsidy until these lower costs were achieved.

In the short term, several road maps for wave energy will be produced, which will deal with the subject in detail. Reviewing the status of those devices at the demonstration/prototype stage and those still in R&D, the time chart shown in Fig. 14-7 indicates the likely progress of various aspects of wave energy in the future.

Conclusions

This is a most interesting time for wave energy. There are a number of ideas and designs for wave energy devices, many of which will be uneconomic and some of which will not work reliably. Care should be taken to identify at an early stage those devices which have poor prospects, in order to make the least use of the limited funds that can be expected for the development of wave energy. There are a few technologies that are ready to be deployed and which show considerable promise. These devices will require some support in order to realise their full potential and, as the following Country Notes show, several governments are providing this. If this situation continues, then within 5 to 10 years' time, wave energy could start to make a significant contribution to energy supply and the provision of potable water.

Tom Thorpe
Oxford Oceanics,
United Kingdom

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COUNTRY NOTES

The following Country Notes on Wave Energy have been compiled by Tom Thorpe and the Editors. Every effort has been made to be comprehensive by making contact with all known wave energy developers. However, it is not an exhaustive list because information is difficult to obtain on some countries and new wave energy devices are being continually conceived. Inclusion of a technology in these notes does not indicate endorsement of that technology. Indeed, there are numerous technologies under development (including some at the prototype stage) that are likely to be uneconomic, if not technically unfeasible.

Wave energy is an immature technology and therefore there are only a few prototype devices installed worldwide, some of which are precursors to the installation of a ‘farm’ of devices. These Country Notes focus on wave energy activities within each country, with no reference to the levels of deployment. The large number of devices under development would make detailed descriptions of them all extremely lengthy. Therefore, only a brief description is given together with the address of a web site for each device, thus enabling the reader to find out more detailed information.

International Bodies

A number of important international bodies have been involved in ocean energy, including wave energy:

The European Commission

This body has sponsored wave-related activities in a number of areas over a considerable length of time. It has promoted cooperation between leading organisations and institutes, via the formation of a Thematic Network (www.wave-energy.net/index3.htm) and a Coordinated Action (www.ca-oe.net). It has made direct contributions towards developing particular technologies, including: shoreline OWCs at Pico in the Azores, the Wave Dragon (www.wavedragon.com), the Wave SSG (www.waveenergy.no) and the SEEWEC (a multinational project to build a device containing an array of wave energy floats, www.seewec.org/). At the present time, the European Commission is considering supporting several other wave devices as well as the European Ocean Energy Association, which has been formed by all stakeholders in ocean energy (both within and outside Europe). Its aim is: to strengthen the development of the markets and technology for ocean energy in the European Union; act as the central network for information exchange and EU financial resources to its members and the promoting of the ocean energy sector by acting as a single EU voice (www.eu-oea.com/).

The International Energy Agency

In 2001, the International Energy Agency (IEA) formed an Implementing Agreement on Ocean Energy (www.iea-oceans.org), which is the IEA’s mechanism for providing a framework for international collaboration in energy technology R&D, demonstration and information exchange. It has grown from the original three Members (Denmark, Portugal and the UK) to nine (Belgium, Canada, the European Commission, Ireland, Japan, USA), with several other countries having been invited to join (Brazil, France, Germany, Italy, Mexico and Norway). This growth reflects how ocean energy is increasingly seen as an viable and important future energy source. The Implementing Agreement has so far completed two important activities: Review, Exchange and Dissemination of Information on Ocean Energy Systems; Development of Recommended Practices for Testing and Evaluating Ocean Energy System.

The European Marine Energy Centre

The European Marine Energy Centre (EMEC) has been established in the Orkney Islands with funding from a number of organisations, Scottish and UK government bodies and the European Commission. It provides four test sites in 50 m water depth for wave energy devices, each with its own subsea cable, as well as a monitoring station and other facilities (www.emec.org.uk). The Centre has hosted a number of wave energy devices (as well as tidal current devices at a nearby site) and is proving pivotal in establishing wave energy as a reliable energy source (e.g. allowing developers to demonstrate their technologies in real sea conditions, coordinating activities around performance measurement and design standards).

Australia

Australia has had little investment in wave energy but developments led by three companies in recent years are stimulating intense interest, especially in using wave energy for desalination of seawater by pumping seawater into reverse osmosis (RO) plant.

Energetech (Australia) Pty Ltd.

Energetech has deployed a prototype tethered 500 kW nearshore OWC device at Port Kembla, New South Wales. It incorporates a parabolic wave collector to focus waves over a wide area onto a central OWC (to compensate for the lower wave power levels near shore) and a novel variable-pitch turbine that has higher efficiencies than turbines normally used in OWCs (www.energetech.com.au). The project has been carried out with support from the Australian Greenhouse Office, under its Renewable Energy Commercialisation Programme. The company has improved on the prototype design by developing a larger floating device rated at up to 2 MW, intended for deeper waters, and a scheme for 10 floating devices, each rated at 1.5 MW, is currently under development for deployment in Portland (Australia) in the near future; some of these will supply an RO unit on the OWC device itself and deliver low-pressure potable water to shore.

Seapower Pacific Pty

Seapower has developed an underwater, sea bed mounted wave energy device (CETO) for delivering pressurised water to an RO plant on-shore (www.seapowerpacific.com). As waves move over the top of the CETO unit, the wave crest depresses a horizontal disk to actuate reciprocating pumps to pressurise water to 7 000 kPa, which is delivered to shore by a small-bore pipe to an RO plant. A prototype device was successfully tested in Western Australia and the company has developed a follow-on design for deployment in 2008/9.

BioPower Systems

BioPower Systems is developing both tidal current and wave energy conversion technologies (www.biopowersystems.com). Their bioWAVE™ wave energy conversion system is based on the swaying motion of sea plants in the presence of ocean waves. Their vertically mounted, waving fronds capture a wide range of incident wave energy without using a large rigid structure and can orientate themselves to the prevailing wave direction. The motion is turned into electricity by their O-DRIVE™ generator, which uses a simple single-stage reciprocating gear mechanism, a direct-drive synchronous permanent magnet generator and high-inertia flywheel to produce smooth AC power. The key innovation is the ability of the system to avoid large loadings in extreme waves by lying flat on the sea bed.

Canada

Canada has not traditionally been thought of as having an interest in wave energy. However, there have been several important developments in recent years, including Canada becoming a member of the IEA's Implementing Agreement on Ocean Energy Systems. A number of organisations have set up the Ocean Renewable Energy Group to promote wave and tidal energy in Canada by addressing common issues (resource assessment, permitting, supply chain); it includes a number of individual device developers (http://oreg.ca). Wave and especially tidal current are seen as a promising energy source, with a number of Provinces actively supporting development projects such as that by BC Hydro for Vancouver Island, where a number of wave and tidal energy developers are seeking to install devices. This activity is starting to be matched at a national level, with the Government undertaking work that will benefit all potential developers, for instance looking into permitting processes.

Canada has several organisations and universities working on wave energy and a few device developers.

Finavera Renewables

This company has taken over the AquaBuOY technology formerly developed by AquaEnergy (www.finavera.com/wave). It consists of a floating, vertical hollow cylinder rigidly mounted under a buoy, with the tube open at both ends so that seawater can pass unimpeded back and forth. Inside the tube are two Hosepumps, one is attached to the top via non-return valves, the other is similarly attached to the bottom and both are attached to a neutrally buoyant disk or piston in the middle. When the buoy is at rest, the piston is held at the midpoint by the balanced tension of the two Hosepumps. When the buoy moves vertically in the waves, the central piston moves with respect to the tube, thereby alternately stretching and compressing the Hosepumps. These are steel-reinforced rubber hoses whose internal volume is reduced when they are stretched, thereby acting as a pump. The pressurised sea water is expelled into a high-pressure accumulator within the buoy which drives a turbine and generator rated at 250 kW. This device has undergone considerable development and is at the pilot plant stage. Finavera has plans for projects in several locations, including a 5 MW scheme in Uculet on the west coast of Canada (later to be upgraded to 100 MW), as well as in the USA, Portugal and South Africa.

SyncWave Energy Inc. (SEI)

SEI is developing a floating device where two floats oscillate out of phase with each other and the relative motion between the floats is harnessed by a mechanical power take-off to generate electricity (www.syncwaveenergy.com). This technology is at the R&D stage.

China

Since the beginning of the 1980s, China's wave energy research has concentrated mainly on fixed and floating oscillating water column devices. In 1995, the Guangzhou Institute of Energy Conversion of the Chinese Academy of Sciences successfully developed a symmetrical turbine wave-power generation device for navigation buoys rated at 60 W. Over 650 units have been deployed along the Chinese coast, with a few exported to Japan.

Other wave energy projects in China include:

- a shoreline OWC at Shanwei in Guangdong province consisting of a two-chambered device with a total width of 20 m, rated at 100 kW began operating in September 1999;
- a 5 kW Backward Bent Duct Buoy (a floating OWC with the opening to the OWC chamber pointing towards the land) in association with Japan;
- a shoreline pivoting flap device (Pendulor) developed by Tianjin Institute of Ocean Technology of the State Oceanic Administration;
- an experimental 3 kW shoreline OWC was installed on Dawanshan Island (in the Pearl River estuary), which is being upgraded with a 20 kW turbine.

Denmark

Between 1998 and 2004 the Danish Energy Agency operated the Danish Wave Energy Programme for supporting development projects initiated by inventors, private companies, universities etc. This covered a wide range of possible converter principles and provided developers with the facilities to have basic research carried out on their devices. At that time, the Danish Wave Energy Association was formed to disseminate information and promote activities for those interested in wave energy.

Several devices have been developed that have been tested at a small scale.

Ecofys

The Ecofys' Wave Rotor comprises a vertical shaft (or monopole) on which a rotor containing both slanted blades (similar to a Darrieus rotor) and horizontal blades. In waves, these experience hydrodynamic lift from the vertical and horizontal components of the motion of particles in the waves. This turns the rotor, which is attached to a 250 kW generator via a gearbox. The key innovations are that, apart from the rotor, there are no other moving parts in the water (the bearings and power take-off are placed 10 m above water level) and the same technology can also extract energy from tidal currents. The concept might also be capable of being mounted on existing structures in the sea. The device has been tested at a small scale in open-sea conditions and is scheduled for tests at 1/5th scale in 2007.

Wave Dragon

The Wave Dragon (a wave concentrating and overtopping device described in the Commentary) is a leading Danish technology. A 20 kW small-scale device is currently operating at Nissum Bredning, the Danish Wave Test Site, which has gained more than 19 500 hours of operating hours experience (www.wavedragon.net). Wave Dragon Wales, a subsidiary of the Danish parent company, is engaged in a project to build a 4-7 MW demonstration device in Wales (www.wavedragon.co.uk). It has formed a project development company, Tecdragon with a group of Portuguese and German investors with the purpose of developing a 50 MW wave energy project in Portuguese waters (www.tecdragon.pt). It has also secured funding from the European Commission for design of a multi-megawatt device.

Wave Plane International A/S

The WavePlane is another floating overtopping device that uses a number of channels for the water to move into, which also act as storage reservoir to smooth out the power. From these, the water is funnelled into a central turbine. Model tests have been carried out in various locations in the world but without any electrical generation. The company additionally proposes to use this device to oxygenate sea water and has representatives in seven countries (www.waveplane.com). This device is at the R&D stage.

Wave Star Energy

The Wave Star device consists of a long structure pointing into the oncoming waves, with a series of floats attached to booms on either side. As a wave travels down the structure, the floats rise and fall, each pressurising its own hydraulic cylinder, which is in turn connected to a common main that powers a central hydraulic motor and generator. The key innovations of the device are the ability to: raise the floats out of the water in large seas; place all the mechanical and electrical plant out of the water on the central structure; perform with only slightly diminished efficiency even when some floats are not functioning. The company, Wave Star Energy, has had a 1/10th scale device with 40 floats of one metre diameter generating up to 5.5 kW connected to the grid since July 2006 and has logged up over 4 000 hours of operation (www.wavestarenergy.com). It has plans for a 500 kW system for use in the North Sea to be installed in 2009.

Finland

Wave energy activities in Finland have been mainly undertaken in universities, with a few exceptions, e.g.:

AW-Energy

This company has developed the WaveRoller. This consists of a vertical buoyant flap hinged along its bottom edge to a structure on the sea bottom. The flap moves back and forth in the waves, operating a piston pump on the sea bed. This can be used directly to operate a hydraulic motor and generator rated at 13 kW or the output of several flaps can be fed into a common hydraulic circuit to power a central generating system, which can be mounted on the shore. The device has been tested at small scale and at 1/3rd scale in the European Marine Energy Centre (EMEC) in Orkney, Scotland (www.aw-energy.com).

France

With its heavy investment and large production from nuclear Pressurised Water Reactor technologies, France has shown little interest in wave energy. However, the École Nationale Supérieure de Méchanique et d'Aérotechnique has carried out an important programme of fundamental research.

Germany

Because of its relatively small resource and low wave-power levels, the only wave energy work undertaken in Germany has been in universities. However, there was an announcement in 2006 of a joint project between Voith Siemens and the German utility EnBW to install a LIMPET OWC plant (see Wavegen in the UK Country Note) on the North Sea coast in 2008/9.

Greece

Greece (like other Mediterranean countries) experiences only low wave-power levels. Nevertheless, it has an R&D programme on wave energy which has been carried out at the

Centre for Renewable Energy Sources and various universities. There were plans for a full scale, semi-commercial demonstration plant for fresh water and electricity production on the island of Amorgos in the South Aegean Sea, based on the technology now being developed by Finavera in Canada.

Daedalus

DAEDALUS Informatics, in coordination with the University of Patras, developed a new device (SEKE), which uses an array of water columns (usually built into a breakwater) to provide compressed air for power generation. Several experimental test scale models of the SEKE device have been developed. Efforts have been focussed on developing a combinatorial system solution, able to harness simultaneously both wave and wind energy using compressed air (http://195.170.12.01/daei/products/ret/general/retww1.html). This device is at the R&D stage.

India

The Indian wave energy programme started in 1983 at the Institute of Technology (IIT) under the sponsorship of the Department of Ocean Development. Initial research identified the OWC as most suitable for Indian conditions: a 150 kW pilot OWC was built onto the breakwater of the Vizhinjam Fisheries Harbour, near Trivandrum (Kerala), with commissioning in October 1991. The scheme operated successfully, producing data that were used for the design of a superior generator and turbine. An improved power module was installed at Vizhinjam in April 1996 that in turn led to the production of new designs for a breakwater comprised of 10 caissons with a total capacity of 1.1 MW. However, this does not appear to have been taken further.

The National Institute of Ocean Technology succeeded IIT and continues to research wave energy including the Backward Bent Duct Buoy (a variant of the OWC design).

Ireland

Ireland has some of the best wave resource in the world and wave energy research has been undertaken there since 1980, with much of the work being conducted at University College Cork (UCC) and Queen’s University Belfast (Northern Ireland), although other universities, such as Limerick, are now playing an increasing role. More recently, the Marine Institute and Sustainable Energy Ireland (SEI) has funded work, for example a wave and tidal energy resource study, as well as helping to develop an ocean strategy (http://www.sei.ie/getFile.asp?FC_ID=1747&docID=913) and supporting several device developers.

Clearpower Technology

Clearpower Technology's Wavebob is a self-reacting point absorber. It comprises two floating bodies mounted vertically that have different responses to waves. This produces relative motion between the bodies, from which energy can be extracted using hydraulics to power a motor and generator. The different frequency responses give the device a greater bandwidth, with scope for tuning over a wider range of sea conditions than is possible with a conventional single buoy point absorber. A 1/4th scale device was deployed in the sea in 2006.

Hydam Technology

Hydam Technology has developed the McCabe Wave Pump. This is a floating device comprising two narrow pontoons that point into the waves and which are attached using hinges to either side of the central generating platform. As waves pass down the length of the device, the pontoons move with respect to the central platform and power is extracted from this movement using hydraulic rams. Although this can be used to generate electricity (~ 400 kW), the device has been designed primarily to produce potable water using reverse osmosis. A prototype scheme was tested in 1996 and a commercial demonstration scheme has more recently been constructed and deployed.

Ocean Energy

Ocean Energy's OE Buoy is a 'backward bent duct buoy', which is a floating OWC with the opening to the OWC pointing away from the incoming waves towards the land. A 1/4th scale device was deployed off the west coast of Ireland in late 2006 and further testing is planned for 2007, before construction of a 1 MW prototype (www.oceanenergy.ie).

Japan

Despite having low wave-power levels, extensive research on wave energy has been undertaken in Japan, which deployed one of the first wave-energy devices (the floating OWC, 'Kaimei'), followed by another floating OWC (the 'Mighty Whale' in 1989). Particular emphasis has been placed on the development of air turbines and on the construction and deployment of prototype devices (primarily OWCs), with numerous schemes having been built:

- a 40 kW OWC was deployed in 1983 on the shoreline structure at Sanze for research purposes. It has since been decommissioned;
- a five-chambered 60 kW OWC was built as part of the harbour wall at Sakata Port in 1989;
- 10 OWCs were installed in front of an existing breakwater at Kujukuri beach, Chiba Prefecture. The air emitted from each OWC was manifolded into a pressurised reservoir and used to drive a 30 kW turbine. This scheme was operational between 1988 and 1997;
- a 130 kW OWC was mounted in a breakwater in Fukushima Prefecture in 1996. This used rectifying valves to

control the flow of air to and from the turbine;

- a floating OWC known as the Backward Bent Duct Buoy was deployed in Japan in 1987. This continues to be developed in co-operation with institutes in China and Ireland;
- the Pendulor wave energy device has been developed by the Muroran Institute of Technology. Wave action causes pendulum oscillations of a plate ('pendulor') at the entrance to a box, this movement being used in conjunction with a hydraulic power take-off to generate electricity.

The only significant wave-energy device currently being studied is an OWC deployed at Niigata in 2005.

Mexico

The only wave-energy activity in Mexico is the development of a wave-driven seawater pump at the Instituto de Ciencias del Mar y Limnología, U.N.A.M., Unidad Académica Mazatlán. This is to be used to recover isolated coastal areas by flushing them out with fresh seawater. A prototype has been successfully tested on the Pacific coast of the state of Oaxaca and a project has been approved to build and install a pump to flush out the port of Ensenada, on the Baja California Peninsula.

Netherlands

The Netherlands experiences low wave-power levels, which has led to Teamwork Technology (www.waveswing.com) seeking to develop their Archimedes Wave Swing (described in the Commentary) in Scotland, where there is a more prospective home market (www.awsocean.com). A 2 MW pilot plant was installed off the coast of Portugal and engineering for a pre-commercial demonstrator is presently being undertaken.

Norway

Research into wave energy has been undertaken at the Norwegian University of Science and Technology (NTNU), Trondheim for the past 30 years and two full-size devices were deployed and operated successfully for a prolonged period during the 1980s. More recently two other devices have been developed.

WAVEenergy AS

The Seawave Slot-Cone Generator (SSG) concept is a shoreline wave-energy converter, based on the wave overtopping principle utilising three reservoirs placed on top of each other. Water captured in each of these reservoirs will then run back to sea through the multi-stage turbine. Multiple reservoirs are used to improve overall efficiency. A 200 kW pilot plant is scheduled to start construction in 2007 (www.waveenergy.no).

SEEWEC

SEEWEC is a consortium involving 11 partners from 5 EU-members (Belgium, Netherlands, Portugal, Sweden and the UK) and 1 associated country (Norway). It aims to build the FO^3, an array of buoys attached to a large floating structure with extensive use being made of composite materials (www.seewec.org). Plans have been made and consent received for 4 x 2.5 MW platforms to be installed in 55 m water depth off the Norwegian coast, in addition to deploying this technology on the Wave Hub (see the UK Country Note).

Portugal

Since 1978 Portugal has played a significant role in wave energy R&D, with considerable work being undertaken at the Instituto Superior Técnico (IST) of the Technical University of Lisbon and the National Institute of Engineering and Industrial Technology (INETI) of the Portuguese Ministry of Economy. Most of the research has been devoted to OWCs and associated turbines, which included the building of a pilot 400 kW OWC plant on the island of Pico in the Azores.

In 2003 the Wave Energy Centre was set up with the objective of providing dissemination, promotion and support to the implementation of wave energy technology and commercialisation of devices. The Centre has a number of ongoing projects, including a 700 kW OWC installed in Foz do Douro breakwater (www.wave-energy-centre.org).

The Portuguese Government is attracting considerable inward investment from wave energy developers by offering enhanced prices paid for electricity derived from wave energy devices (initially, approximately US$ 0.30/kWh). Projects confirmed to date include: a 2.25 MW scheme consisting of 3 Pelamis devices which have already been delivered (www.oceanpd.com) and a 2 MW scheme using the AquaBuOY technology (www.finavera.com/wave), with interest from several others.

Spain

Little indigenous work on wave energy has been undertaken in Spain. However, Spain has also attracted wave energy developers including: Energetech (Australia) for a 1 MW OWC scheme in the port of Bilbao; Ocean Power Technologies (USA) for an initial 40 kW device at Santoña (to be increased to 9 x 150 kW devices, if successful); Wavegen (UK) for a 480 kW shoreline scheme consisting of 16 x 30 kW OWCs built into a shoreline facility in the Basque country.

Sri Lanka

The Ministry of Science and Technology has a two-stage project to survey the wave energy potential of the island. The first stage has established that the potential in the southern coastal belt is around 10-15 kW/linear m. The purpose of the second stage, currently under way, is to design a prototype plant, for which funding is being sought.

Sweden

Sweden has played a significant role in wave energy, despite having a relatively poor wave energy resource. Activity has been mainly in academia, with Chalmers Tekniska Hogskola and Uppsala University making the most contributions. One company, AB Interproject Service AB, has developed the concept of combining the IPS buoy and the Hose-Pump converter, which is the system now being exploited by Finavera (Canada).

Seabased AB

This device is a moored floating buoy affixed via a rope to a 10 kW electrical generator mounted on the sea bed. The key innovation of this technology is its use of a linear generator with a large number of NdFeB magnets, which allows for high magnetic excitation with smaller magnets (www.seabased.com).

Sea Power International

This company has developed a floating overtopping device for mooring in deep water (www.seapower.se/indexeng.html). A considerable time ago it won an opportunity to install a device in Shetland as part of the Scottish Renewables Order but little progress has since been made.

United Kingdom

At one time the UK had one of the largest government-sponsored R&D programmes on wave energy. After a period of reduction, interest has been renewed in recent years, with government-funded research at a number of universities and institutions as well as support for different device developers. There have been a number of initiatives that benefit the ocean energy sector in general:

- development of a market pull price mechanism (similar to Portugal's). The Scottish Executive has confirmed a generous mechanism for the first wave energy scheme (which has already attracted one developer – OPD) and a decision on the price for the rest of the UK is expected shortly;
- establishing a range of wave energy test facilities, ranging from wave tanks, dry-dock testing of large scale devices (e.g. the New and Renewable Energy Centre – NaREC – www.narec.co.uk/facilities-wave-and-tidal-dock.php), test stations for full size devices at sea (www.emec.org.uk) and a facility that will eventually provide a test station for small arrays of full-size devices at sea (the Wave Hub - www.wavehub.co.uk);
- government support for developers of ocean energy devices in the form of direct grants and, more recently, a marine resources development fund of nearly US$ 100 million for pre-commercial devices;

- support for wave energy through official organisations such as the Carbon Trust (www.thecarbontrust.co.uk). This has carried out an assessment of ocean energy devices, established a marine technology accelerator fund and invested in one wave energy device;
- established coordinated academic research on wave energy in several universities (www.supergen-marine.org.uk).

Many different devices at various stages of maturity continue to be developed in the UK under the above initiatives. Among the leading developers are:

Aquamarine Power

This company has developed the Oyster™, a near-shore bottom-mounted wave energy converter for use in water depths of around 12 m. It is an oscillating flap device, similar to the WaveRoller (see the Finland Country Note). It delivers pressurised seawater to the power take-off unit (i.e. conventional hydro-electric generators) on the shore. A full-size prototype device is being tested at EMEC (www.aquamarinepower.com).

C-Wave

C-Wave Ltd has designed a large wave-energy device in which buoyant vertical flaps or 'walls' are mounted via hinges on a long floating platform at a distance of approximately half an ocean wavelength apart. These flaps oscillate back and forth under wave action, activating a hydraulic pump mounted between each flap and the platform. The key innovation of this device is by using such a wide separation, the two flaps experience the peak and trough of a wave, thereby cancelling out any horizontal motion and reducing mooring loads. The device is still at the R&D stage (www.cwavepower.com).

University of Manchester Intellectual Property Ltd

The University of Manchester is developing the Manchester Bobber, which comprises 25-50 floating masses, suspended by wires below a platform in up to 60 m water depth. The masses rise and fall under the action of waves turning a pulley and its shaft in one direction (by using a freewheel clutch). This in turn drives an electric generator via a gearbox. The main advantage is that the pulley and all associated mechanical and electrical equipment are mounted on the platform above the waves. This device is at the R&D stage (www.manchesterbobber.com).

Ocean Power Delivery (OPD)

The technology behind OPD's Pelamis has been briefly described in the Commentary (www.oceanpd.com). It has been tested at full scale at EMEC and has contracts in place to deploy 3 devices in Portugal, 4 devices in Orkney and up to 7 devices at the Wave Hub in the UK. This is clearly the UK's leading device.

ORECon

The ORECon concept is a floating OWC employing a multiple oscillating water column configuration (rather than the single chamber used by other OWC devices) and a self-rectifying impulse turbine. By combining multiple columns within the collector component, the device can be tuned to resonate at multiple rather than single frequencies to capture energy over a much broader waveband. This device is at the R&D stage.

Offshore Wave Energy Ltd (OWEL)

The OWEL is a very large floating platform containing several horizontal channels facing into oncoming waves, which have decreasing cross sectional areas as the waves travel down the channels. These trap the air between successive wave peaks and compress it before discharging into a reservoir, where it is then used to drive a turbine and thus generate power (www.owel.co.uk). This device is at the R&D stage.

Wavegen

Wavegen's pioneering shoreline OWC (the LIMPET) continues to function on the island of Islay. Its output is fed into the local grid but the plant also serves as a test bed for new technology. Wavegen has advanced plans for deploying such devices in Scotland and in Germany, as well as developing its OWC concept for use in arrays of small OWC chambers within breakwaters (www.wavegen.com).

Trident Energy

This device consists of a floating buoy contained within a floating structure. The vertical movement of the buoy with the rise and fall of the waves is directly coupled to a linear generator on the platform (www.tridentenergy.co.uk). This device has been tested at NaREC and is still at the R&D stage.

United States of America

For a prolonged period, there was no official interest in wave energy in the USA. A number of devices were conceived but few made it past the drawing board. However, interest in wave energy has recently been rekindled, thanks in part to an extensive study undertaken by the Electrical Power Research Institute (www.epri.com/oceanenergy/waveenergy.html), which made a 'compelling case for investment in wave energy'. This interest is reflected at both a national and state level and a number of technologies have been developed.

Aerovironment (AV)

AV's device consists of a buoy anchored to the sea floor so that it floats beneath the surface (www.avinc.com/energy_lab_project_detail.php?id=68). As the float moves through the water vertically, responding to changes in pressure resulting from passing waves, it powers a generator on the sea bed (mechanism unspecified). A scale model completed testing in the Pacific Ocean with encouraging results, and plans for broad deployment are being developed. This concept is at the R&D stage.

Ocean Motion International

Ocean Motion International's technology uses a large buoyant vessel to which a number of heavy ballast masses are attached via a sleeve-type pump. The masses rise and fall in the waves, pumping water into a manifold to power a hydroelectric generator or a reverse osmosis (RO) unit. This concept is at the R&D stage (www.oceanmotion.ws).

Ocean Power Technologies (OPT)

OPT has a long history of developing its PowerBuoy™. This system consists of a floating buoy that is moored to the sea bed so that it can freely move up and down in response to the waves. The movement is converted into rotational mechanical energy, which in turn drives the electrical generator, all of which are in a sealed unit. The control system collects data and adjusts the performance of the PowerBuoy™ system in real-time and on a wave-by-wave basis. The current device is about 17 m long, 3 m in diameter and is rated at 40 kW but OPT has plans for a 500 kW PowerBuoy™ system, with a diameter of nearly 14 m and a length of 20 m (www.oceanpowertechnologies.com). OPT has deployed single devices in Atlantic City (New Jersey) and Oahu (Hawaii) and has an agreement for another device at Santoña (Spain). Typically, these agreements allow OPT to demonstrate the performance of its device before going on to install arrays. OPT is the only wave energy developer to have successfully floated on the stock market, but it is expected that others will try to follow in 2007/8.

Independent Natural Resources, Inc. (INRI)

INRI™ has recently developed the SEADOG™ pump (www.inri.us). This comprises a large piston operating over an air-filled buoyancy chamber. The piston moves up and down with the varying pressure under wave peaks and troughs and this movement drives a hydraulic pump to produce pressurised water, which is pumped to shore to produce potable water (via an RO unit) or electricity by filling a reservoir which is allowed to drain back to the sea via hydroelectric turbines. Each pump can produce several tens of kilowatts of power, so in practice an array of devices will be deployed. A single SEADOG™ prototype has been successfully tested in the Gulf of Mexico and the company has plans for deployment of a 16 device array off the Californian coast, which will produce just over 500 kW.

Scientific Applications & Research Associates (SARA)

SARA has developed a wave energy device to extract energy from waves using a magnetohydrodynamics (MHD) generator. It is designing a 100 kW prototype to demonstrate this principle, as well as developing a deep-ocean-moored device to use the MHD generator. This device is at the R&D stage (www.sara.com).

Seavolt

Seavolt's Wave Rider consists of a moored cam-shaped buoy which bobs up and down in the waves. This rolling action powers a hydraulics circuit connected to a motor and generator. The current status of this device is uncertain.

15. Ocean Thermal Energy Conversion

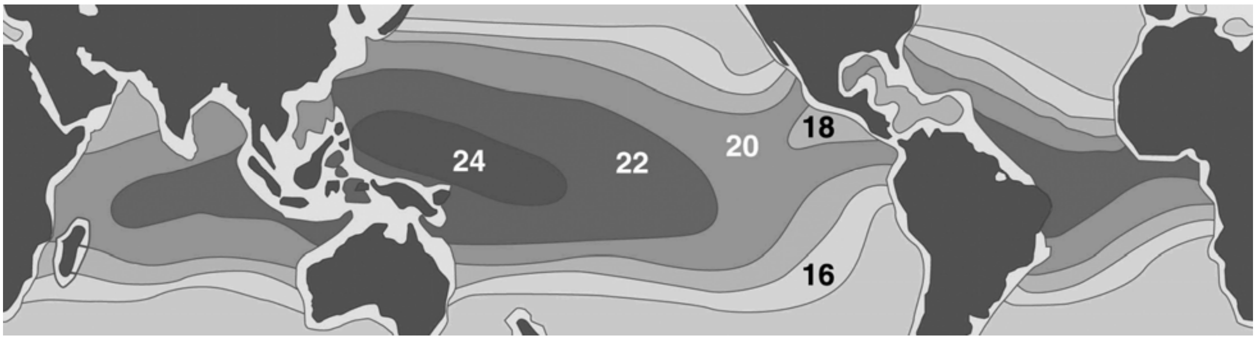
COMMENTARY

Introduction

Since the WEC *Survey of Energy Resources* (SER) 2004, the most significant - some would say substantial - change in the energy scene has been the very large increase in the price of oil from, typically, US$ 25-30/bbl to as much as US$ 70/bbl, with a possible "settling" point for the next few years of around US$ 50/bbl. Clearly this basic doubling of the oil price has a major effect on the comparative economics of all other energy supply systems - from all renewables to nuclear. As noted later, the climate change imperatives are also now accepted in a majority of countries, and these too have a direct impact on the costs of generation from all energy sources - for better or worse, depending on the particular energy source being considered. The costings in this chapter seek to take note of these changes.

Ocean Thermal Energy Conversion (OTEC) is a means of converting into useful energy the temperature difference between the surface water of the oceans in tropical and sub-tropical areas, and water at a depth of approximately 1 000 metres, which comes from the polar regions. Fig. 15-1 shows the temperature differences in various parts of the ocean, and for OTEC a temperature difference of 20^{o}C is adequate, which embraces very large ocean areas, and favours islands (Gauthier & Lennard, 2001) and many developing countries.

Figure 15-1 The area available for OTEC and the temperature difference
Source: Xenesys Inc.



The continuing increase in demand from this sector of the world (as indicated by World Energy Council data) provides a major potential market. Specifically the percentage of 'new' energies will grow – from a near-zero figure at the end of the 20th century to 6% by the year 2020, which translates into 'new' energies of some 12 000 MW a year, averaged over the period from 2000 to 2020. There is now a case for the use of OTEC power in nations located in temperate zones, via the production and trans-shipment of liquid hydrogen, which will add to the 12 000 MW figure, but at this time a quantification cannot be reliably estimated.

Figure 15-2 Less developed countries with adequate ocean thermal resources, 25 km or less from shore
Source: Cogeneration Technologies

Country / Area	Temperature Difference (^{o}C) of Water Between 0 and 1 000 m	Distance from Resource to Shore (km)
Africa		
Benin	22-24	25
Gabon	20-22	15
Ghana	22-24	25
Kenya	20-21	25
Mozambique	18-21	25
São Tomé and Príncipe	22	1-10
Somalia	18-20	25
Tanzania	20-22	25
Latin America and the Caribbean		
Bahamas	20-22	15
Barbados	22	1-10
Cuba	22-24	1
Dominica	22	1-10
Dominican Republic	21-24	1
Grenada	27	1-10
Haiti	21-24	1
Jamaica	22	1-10
St Lucia	22	1-10
St Vincent & the Genadines	22	1-10
Trinidad & Tobago	22-24	10
US Virgin Islands	21-24	1
Indian and Pacific Oceans		
Comoros	20-25	1-10
Cook Islands	21-22	1-10
Fiji	22-23	1-10
Guam	24	1
Kiribati	23-24	1-10
Maldives	22	1-10
Mauritius	20-21	1-10
New Caledonia	20-21	1-10
Pacific Islands Trust Territory	22-24	1
Philippines	22-24	1
Samoa	22-23	1-10
Seychelles	21-22	1
Solomon Islands	23-24	1-10
Vanuatu	22-23	1-10

The capital cost of OTEC plants has increased in the last 3 years, owing to the very significant rise in many material costs during that period, which must be added to the high costs resulting from the inherent low efficiency of this technology. Against this can be set reductions, firstly resulting from the lower interest rates in recent years and practically due to improvements in, for example, heat exchangers. This results overall in capital costs of the order of US$ 7 000-15 000/kW, still some ten times the capital cost for conventional power systems. The funding of all 'new' energies would therefore equate to a total sum each year in the region of US$ 75-150 billion: by any standards this is very substantial business, and for the construction, operational and financing sectors, an activity of very considerable interest. But the OTEC business will only develop if it is economically attractive to the utilities that will invest in and operate it – and this situation has now arrived for a number of potential locations.

Whilst the ocean thermal resource is relevant, particularly to many developing countries, there are a multitude of other factors to be considered before it can be said that a particular country or location is suitable for an OTEC installation. These include: distance from shore to the thermal resource; depth of the ocean bed; depth of the resource; size of the thermal resource within the Exclusive Economic Zone (EEZ); replenishment capability for both warm and cold water; currents; waves; hurricanes; sea bed conditions for anchoring; sea bed conditions for power cables of floating plants; present installed power, and source; installed power per head; annual consumption; annual consumption per head; present cost per unit – including any subsidy; local oil or coal production; scope for other renewables; aquaculture potential; potable water potential; and environmental impact – to name but a few. For completeness it would be useful to seek whole-life nuclear-power costings so that comparative capital and generating costs for all energy sources are clearly indicated.

Types of OTEC Plant

Depending on the location of the cold and warm water supplies, OTEC plants can be land-based, floating, or – now not such a longer-term development – grazing. Floating plants have the advantage that the cold water pipe is shorter, reaching directly down to the cold resource, but the power generated has to be brought ashore, and moorings are likely to be in water depths of, typically, 2 000 metres. The development of High Voltage DC transmission offers substantial advantage to floating OTEC, and the increasing depths for offshore oil and gas production over the last decade mean that mooring can now be classed as 'current technology'– but remains a significant cost item for floating OTEC. Land-based plants have the advantage of no power transmission cable to shore, and no mooring costs. However, the cold water pipe has to cross the surf zone and then follow the seabed until the depth reaches approximately 1 000 metres – resulting in a much longer pipe which has therefore greater friction losses, and greater warming of the cold water before it reaches the heat exchanger, both resulting in lower efficiency.

The working cycle of an OTEC plant may be closed or open, the choice depending on circumstances. All these variants clearly develop their power in the tropical and sub-tropical zones (Fig. 15-1), to the benefit of countries in those parts of the world, but a grazing plant would allow OTEC energy use in highly-developed economies which lie in the world's temperate zones. In this case, the OTEC plant is free to

Some floating OTEC plants would actually result in net CO_2 absorption.

drift in areas of ocean with a high temperature difference, the power being used to split sea water into liquid hydrogen and liquid oxygen. The hydrogen, and in cases where it is economic, also the oxygen, would be offloaded into shuttle tankers which would take the product to energy-hungry countries, where the infrastructure for liquid hydrogen distribution is now being initiated - for example in California. Also, the hydrogen may be an intermediate product, being used in turn to produce ammonia. At present, use of ammonia fertilisers is determined in part by production capacity from natural gas; the use of such fertilisers in the developing world – much of it in the tropical and sub-tropical zones where OTEC processes are available – could make a major contribution to world food production.

An especial benefit of OTEC is that, unlike most renewable energies, it is base-load – the thermal resource of the ocean ensures that the power source is available day or night, and with only modest variation from summer to winter. It is environmentally benign, and some floating OTEC plants would actually result in net CO_2 absorption. And a further unique feature of OTEC is the additional products which can readily be derived – food (aquaculture and agriculture); pharmaceuticals; potable water; air conditioning; etc. Many of these arise from the pathogen-free, nutrient-rich, deep cold water. OTEC is therefore the basis for a whole family of Deep Ocean Water Applications (DOWA), which can additionally benefit the cost of generated electricity. Potable water production alone can reduce electricity generating costs by up to one-third, and is itself in very considerable demand in most areas where OTEC can operate.

In order to incorporate all these variables into an economic model it is necessary to assess:

- the objectives of each application;
- the state of the art;
- other fields of application for the technology;
- opportunities for further development.

Economics and Finance

Although these additional products offer significant potential improvements to the economy of OTEC, a contributory reason to the lack of commercialisation of OTEC/DOWA to date is that the economic benefits of these products have generally still not been integrated into the scenarios of development. It is difficult at present to measure these benefits accurately, and only the potable water production benefit has been quantified. The relevance of environmental impact was given a considerable boost by the Rio and Kyoto summits, and follow-up actions have included a much greater emphasis on this aspect by a number of countries and energy companies, including the impact of a Carbon Tax in various forms on fossil fuels. When these are brought into full use – as may well be the case in the first decade of the 21^{st} century – then all renewables, including OTEC, will benefit further in terms of competitiveness with hydrocarbons. Calculations

OTEC/DOWA is now an attractive economic option in a number of locations.

of generating costs should already take increasing account of this and other ‘downstream environmental factors’. Even without such criteria being included, OTEC/DOWA is now an attractive economic option in a number of locations.

Quite apart from this aspect, technological improvements – such as the much smaller heat exchangers now required – have contributed to significantly reduced capital expenditure - but in common with all other capital plants, expenditure has increased in line with higher material costs. Also, the world-wide trend to whole-life costing benefits all renewables when compared with those energy systems which rely on conventional fuels (and their associated costs), since the fuel for OTEC is totally free. Even when the higher initial maintenance costs of early OTEC/DOWA plants are taken into account, net benefits remain. As a result, when compared with traditional fuels the economic position of OTEC/DOWA is now rapidly approaching equality - and in certain locations surpassing it. Work in Hawaii at the Pacific International Center for High Technology Research (PICHTR) has contributed to realistic comparisons, as well as component development.

Nations which previously might not have contemplated OTEC/DOWA activities have been given legal title over waters throughout the 200 nautical mile EEZ associated with the UN Convention on the Law of the Sea (UNCLOS). Prior to that, no investor – private or public – would seriously contemplate funding a new form of capital plant in such seas and oceans, but since UNCLOS a number of nations have worked steadily to prepare overall ocean policies and recent years have seen a number of these introduced – for example in Australia.

Despite the existence of EEZs, the low first costs of many ‘traditional’ energy resources in the recent past had not encouraged venture-capital investment in OTEC/DOWA, but the currently very much higher costs of oil, plus the growing recognition of the environmental effects (and their costs) of some traditional fuels, are changing the economics of these in relation to OTEC/DOWA and other renewables.

It is *all* these factors which now put OTEC/DOWA on a fully economic commercialisation basis in comparison with established energy sources. The 2004 SER suggested that this might occur ‘early in the 21st century’ - and so it has proved to be. But, whilst most of the components for an OTEC/DOWA plant are either immediately available, or nearly so, the inherent simplicity of a number of key elements of these plants still have opportunities for further refinement through continuing R,D&D investment. But with current competitive economics there remains the need to show clearly to potential investors, via a demonstration-scale plant such as that of 1-1.2 MW now being constructed in Hawaii for operation in 2009, that the integrated system also operates effectively, efficiently, and safely.

A Typical OTEC Design

To put this into perspective, consider a specific design for an OTEC plant. The example described is a 10 MW closed cycle floating OTEC plant, for application in a specific Caribbean or South Pacific island site. It was initially designed in the mid-1980s and has been progressively updated. Landed costs for fuel oil in these islands can be 75% higher than in mainland locations - US$ 50+/bbl rather than the US$ 30/bbl which has typified continental prices over the last decade - although in 2006 prices were double the latter figure.

Power generation is provided by two of the three 5 MW power 'pods'. The concept recognises that, as a 'demonstrator plant', reliability will be lower than for a production plant, and the third power pod is included both for development work and as a standby for times when a production pod is out of use either for regular service or an unscheduled outage. The two sites chosen have the cold deep resource close to shore – in the Caribbean the 1 000 m depth being no more than 2.5 km from shore, and the minimum measured temperature difference between the surface and that depth being 21^{o}C, increasing to 23^{o}C at the warmest time of year. The 21^{o}C difference is used as the basis for calculation, which results in an overall efficiency of 2.7%. This compares with an efficiency value for diesel fuel power plants of 25-35%, and values at the upper end of that range for a modern fossil-fuel power station.

Specific costs of individual components were calculated, and used as the basis for total capital, and then derived generating costs, the latter incorporating all operating, maintenance and insurance costs in addition. Contingencies were assessed, with the cold water pipe having the lowest confidence level - but with component replacement techniques included.

Total estimated cost for the plant, in 2006 dollars, incorporating the target costs for components as a basis, is US$ 115 million which, depending on the contingencies, could increase by as much as 25% or decrease by up to 13%.

A discount rate of 5% was used, on the basis that this demonstrator plant was akin to a public sector project. Although the design life of the plant was 25 years, payback was taken as 10 years – a stringent assumption, with interest charged at 11%, which with present lower levels of interest rates worldwide, may also be unduly harsh. Annual inflation rates were assumed at 5% and again this is possibly pessimistic in the present industrial climate.

Availability of the plant was assessed at 90%. This would be high for a normal demonstrator, but here the third pod is available as standby. The resulting calculated generating cost was 21 cents/kWh, with no allowance for potable water production since, as a floating plant, desalination can only be provided as a by-product of electricity generation. However, if the price of water is high enough, a financial credit will be obtained. Using the PICHTR calculations as a basis, the generating costs for this 10 MW-sized plant would fall from 21 cents/kWh by approximately 4 and 7 cents/kWh respectively, to 17 and 14 cents/kWh, corresponding to potable water credits of 40 cents/m^3 and 80 cents/m^3. Since potable water in Pacific islands can cost from 40 cents/m^3 up to US$ 1.60/m^3, the generating cost of 14 cents/kWh – corresponding to a water credit of 80 cents/kWh – is considered realistic.

Other potential by-products, described earlier, are ignored because the quantities needed here are small when compared with those available from the OTEC/DOWA plant, and initially will have only a small influence on the overall economy, although the human benefits of these by-products to a population may well be considerable. In the present calculations, therefore, no benefit is claimed for these by-products in terms of reduced generating costs for electricity from the OTEC plant.

The remaining economic item to consider is 'environmental benefit' – or put the other way, the proposed 'Carbon Taxes'. Such taxes would clearly benefit a renewable energy system, such as OTEC. The proposed levels of such a tax have varied considerably, from as little as US$ 3/bbl to as much as US$ 13/bbl, which would result in a likely 'effective benefit' further to decrease OTEC/DOWA generating costs by between 0.5 and 3 cents/kWh.

All these calculations have been for a demonstration plant. On the assumption that, without any benefits of major re-design, but with operating experience to refine detail design, manufacture and operation, the overall improvement in the system for the eighth production 10 MW floating plant is calculated to achieve a significant 30% reduction in electricity generating cost; that is to 14.7 cents/kWh for the basic OTEC plant, and to 11.9 and 9.8 cents/kWh respectively with water revenues at the levels of 40 cents/m^3 and 80 cents/m^3.

Whilst these generating costs are now competitive for a number of island sites with conventional sources for electrical power generation, the OTEC plant must also be attractive to the utility that is to operate it. For the 10 MW plant described here the rates of return are 20.4% (nominal) and 14.7% (real), which are reasonably attractive in terms of accepted commercial practice.

For this demonstration plant, the prospects for both plant operator and the consumer of electricity are looking genuinely competitive, a significant change from the situation just 10 years ago. On a simple costing basis OTEC is becoming economically attractive, with its DOWA and environmental benefits as a bonus, over and above the base economic case.

The Way Ahead and the Market

As with most new technologies, the financial sector is slow to involve itself until one or more representative demonstration plants have operated successfully - and this has proved to be true in the past for OTEC technology. However, with the progressive reduction in risks - for example the mooring of a floating OTEC plant will now be an application of 'routine' offshore oil and gas experience - a number of more enlightened financial bodies are now prepared to become involved at this relatively early stage of development. Other funding sources would include agencies such as the World Bank or European Development Bank and a further potential source of funding is possible through the Lomé and Cotonou Agreements between the European Union and the Africa–Caribbean–Pacific (ACP) States, many of which are prime candidates to use OTEC power.

In Europe both the European Commission and the industrially-based Maritime Industries Forum examined OTEC opportunities with relevance to DOWA in general rather than just OTEC, and the UK published its Fore*sight* document for the marine sector, looking five to twenty years ahead, and both OTEC and DOWA were included in the energy section of the paper. It is significant that the emphasis in the recommendations from all three European groupings has, again, been on the funding and construction of a plant in the 5-10 MW range.

Current US activity is concentrating on an Indian Ocean island site, and it is perhaps noteworthy that both Japanese and British evaluations continue to identify Fijian prime sites, one each on the two largest islands of that country.

The worldwide market for all renewables has been estimated for the timescales from 1990 to 2020 and 2050, with three scenarios and, not surprisingly, all show significant growth. Within those total renewable figures, opportunities exist for the construction of a significant amount of OTEC capacity, even though OTEC may account for only a small percentage of *total* global electricity generating capacity for some years. Estimates have been made by French, Japanese, British and American workers in the field, suggesting worldwide installed power for up to a thousand OTEC plants by the year 2010, of which 50% would be no larger than 10 MW, and less than 10% would be of 100 MW size. On longer timescales, the demand for OTEC in the Asia/Pacific region has been estimated at 20 GW in 2020 and 100 GW in 2050 (OECD, 1999). It has to be said that some of these numbers seem optimistic, with realisation depending on the successful operation of a number of demonstrator plants at an early date.

In summary, however, it can realistically be claimed that the economic commercialisation of OTEC/DOWA is ‘now’ – nearly all the technology is established, and the greatest concentration of effort seems logically to be aimed at lining up an increased range of suitable funding sources.

Don Lennard

Ocean Thermal Energy Conversion Systems Ltd, United Kingdom

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COUNTRY NOTES

The Country Notes on OTEC compiled for previous editions of the *Survey of Energy Resources* have been revised, updated and augmented by the Editors, using national sources, other information and personal communication. Valuable inputs were provided by Don Lennard of Ocean Thermal Energy Conversion Systems Ltd.

American Samoa

In mid-2006 it was reported that the country's Power Authority was being supported by the US Department of the Interior in an investigation into using its available OTEC resource to replace fossil fuel-generated electricity.

Antigua

At the beginning of 2006 the Chief Environment Officer of Antigua announced that an MOU for an OTEC feasibility study was being prepared with an American organisation.

Australia

At an ocean energy workshop held in Townsville, northern Queensland in September 2005, discussion concentrated on developing OTEC energy in the region. It was suggested that the city could act as the 'launch pad' for plants in the South Pacific and also, in time, become a centre of excellence in the technology.

To date the plans have not progressed owing to environmental concerns for any such scheme and also a greater interest in other alternative energy sources.

Barbados

With the high petroleum product prices of recent years, Barbados is considering substituting a fossil fuel-based power supply for one utilising the renewable energies. In late-2004, an American developer announced that it was interested in helping Barbados establish an OTEC plant for electricity generation and mariculture purposes.

Cayman Islands

Caribbean Utilities Company (CUC) stated during 2006 that it was exploring the possibilities of utilising the country's ocean thermal resource for the production of electricity and fresh water. An American developer would plan for a prototype plant to be installed but purchase agreements between CUC, Cayman Water Authority and/or Cayman Water Company would need to be settled prior to any deployment.

Côte D'Ivoire

A French project to build two open cycle onshore OTEC plants of 3.5 MW each in Abidjan was proposed in 1939. The experimentation was eventually undertaken after World War II, with the main research effort occurring during 1953-1955. The process of producing desalinated water via OTEC proved to be uneconomic at that time and the project was abandoned in 1958.

Cuba

This was the site of the first recorded installation of an OTEC plant and the island remains a very desirable location in terms of working temperature difference (in excess of 22^{o}C). Georges Claude, a French engineer, built an experimental open cycle OTEC system (22 kW gross) at Matanzas in 1929-1930. Although the plant never produced net electrical power (i.e. output minus own use) it demonstrated that the installation of an OTEC plant at sea was feasible. It did not survive for very long before being demolished by a storm.

Fiji

This group of islands has been the subject of OTEC studies in the UK and in Japan. In 1982 the UK Department of Industry and relevant companies began work on the development of a floating 10 MW closed cycle demonstration plant to be installed in the Caribbean or Pacific. The preferred site was Vanua Levu in Fiji.

At end-1990 a Japanese group undertook an OTEC site survey on the Fijian island of Vitu Levu. Design work on an integrated (OTEC/DOWA) land-based plant was subsequently undertaken.

The studies have not given rise to any firm construction project. However, when the tourist industry grows further, the Vanua Levu site will again be ideal, with cold deep water less than 1 km from shore. The development of the tourist industry will require substantial electrical power, potable water and refrigeration.

French Polynesia

Feasibility studies in France concluded that a 5 MW land-based pilot plant should be built with Tahiti as the test site. An industrial grouping, Ergocean and Ifremer (the French institute for research and exploitation of the sea) undertook extensive further evaluation (of both closed and open cycle) and operation of the prototype plant was initially expected at the end of the 1980s, but the falling price of oil caused development to be halted. Ifremer continues to keep the situation under review and has been active in the European Union.

Specifically, Ifremer with various partners has examined DOWA desalination, since a much smaller (1 m diameter) cold water pipe would be needed. Techno-economic studies have been completed but further development is on hold.

Guadeloupe

Experimental studies on two open cycle plants were undertaken by France between the mid-1940s and the mid-1950s in Abidjan, Côte d'Ivoire. The results of these studies formed the basis of a project to build an OTEC plant in Guadeloupe (an Overseas Department of France) in 1958. This onshore 3.5 MW OTEC plant was intended to produce desalinated water but the process proved to be uneconomic at that time and the project was abandoned in 1959.

India

Having an extremely long coastline, a very large EEZ area and suitable oceanic conditions, India's potential for OTEC is extensive.

Conceptual studies on OTEC plants for Kavaratti (Lakshadweep Islands), in the Andaman-Nicobar Islands and off the Tamil Nadu coast at Kulasekharapatnam were initiated in 1980. In 1984 a preliminary design for a 1 MW (gross) closed Rankine Cycle floating plant was prepared by the Indian Institute of Technology in Madras at the request of the Ministry of Non-Conventional Energy Resources. The National Institute of Ocean Technology (NIOT) was formed by the governmental Department of Ocean Development in 1993 and in 1997 the Government proposed the establishment of the 1 MW plant of earlier studies. NIOT signed a Memorandum of Understanding with Saga University in Japan for the joint development of the plant near the port of Tuticorin (Tamil Nadu).

During 2001 the Department of Ocean Development undertook an exercise to determine the actions required to maximise the country's potential from its surrounding ocean. The result was a Vision Document and a Perspective Plan 2015 (forming part of the 10th 5-year plan) in which all aspects of the Indian Ocean will be assessed, from the forecasting of monsoons through the modelling of sustainable uses of the coastal zone to the mapping of ocean resources, etc.

It has been postulated that most of India's future fully-commercial OTEC plants will be closed cycle floating plants in the range 10-50 MW (although 200-400 MW plants are not ruled out). Working with Saga University, NIOT had planned to deploy the 1 MW demonstration plant in March/April 2003. However, mechanical problems prevented total deployment and the launch was delayed. Following testing, it was planned to relocate the plant to the Lakshadweep Islands for power generation prior to full commercial operation from scaled-up plants. No further progress has been reported.

Indonesia

A study was carried out in the Netherlands for a 100 kW (net power) land-based OTEC plant for the island of Bali, but no firm project has resulted.

Jamaica

In 1981 it was reported that the Swedish and Norwegian Governments, along with a consortium of Scandinavian companies, had agreed to provide the finance required for feasibility studies towards an OTEC pilot plant to be located in Jamaica.

In a reference to OTEC, the National Energy Plan (circa 1981) stated that 'a 10 MW plant was envisioned in the late 1980s'. Although this project never came to fruition, a plan remains in place for an offshore 10 MW plant producing energy and fresh water. For implementation to take place, purchasing agreements from the power and water utility companies need to be in place.

There was further discussion regarding Jamaica's ocean thermal resource at the beginning of 2005 and the Ministry of Industry, Technology, Energy and Commerce continues to list OTEC as a possible energy supply to the island, but to date there has been no development.

Japan

Research and development on OTEC and DOWA has been carried out since 1974 by various organisations (Ocean Thermal Energy Conversion Association of Japan; Ocean Energy Application Research Committee, supported by the National Institute of Science and Technology Policy; Japan Marine Science and Technology Center, Deep Seawater Laboratory of Kochi; Research Institute for Ocean Economics and Toyama prefectural government; Saga University; Electrotechnical Laboratory and Shonan Institute of Technology).

Saga University conducted the first OTEC power generation experiments in late-1979 and in early-1980 the first Japanese experimental OTEC power plant was completed in Imari City.

During the summer months of 1989 and 1990 an artificial up-welling experiment was conducted on a barge anchored on the seabed at 300 m offshore in Toyama Bay.

With the establishment in 1988 of the OTEC Association of Japan, now the Japan Association of Deep Ocean Water Applications (JADOWA), the country has placed greater emphasis on products that use deep ocean water in the manufacturing process. Such products (food and drink, cosmetics and salt) have all proved commercially successful.

In March 1996, a Memorandum of Understanding was signed between Saga University and the National Institute of Ocean Technology of India. The two bodies have been collaborating on the design and construction of a 1 MW plant to be located off the coast of Tamil Nadu in India.

In mid-2003 Saga University's Institute of Ocean Energy (IOES) inaugurated a new research centre for the study of OTEC.

During 2003 it was reported that Saudi Arabia had shown great interest in working with Saga University to develop the Kingdom's OTEC potential.

If the OTEC projects the university is helping to implement are proved to be viable, the enormous potential of Japan's own EEZ could be exploited in the future.

Kiribati

During late-1990, an OTEC industrial grouping in Japan undertook detailed research (including the water qualities of the ocean, seashore, lagoon and lakes) on Christmas Island. Following on from this research, the basic concepts were improved but no developments have ensued.

Kuwait

In May 2007 Kuwait National Petroleum Company signed an MOU with Xenesys of Japan for the application of OTEC technology to power generation and water desalination, using waste heat from KNPC refineries.

Marshall Islands

In the early 1990s the Republic of the Marshall Islands invited proposals from US companies to undertake a detailed feasibility study for the design, construction, installation and operation of a 5-10 MW (net) OTEC power plant to be located at Majuro. The contracted study was carried out by Marine Development Associates of California between April 1993 and April 1994 but no project resulted.

At a forum convened prior to the World Water Forum (Kyoto, March 2003) by Japan's Saga University and the Government of Palau (a group of Pacific Islands to the east of the Marshall Islands), interest was renewed in the possibility for OTEC installations. The success of the planned project in Palau could well prove to be the impetus required for development in the Marshall Islands and other Pacific Islands.

Mauritius

With its heavy dependence on imported fossil fuels for energy supply, Mauritius has increasingly been looking at developing the renewable energies available to the Republic. In 2005 Xenesys, and Saga University, both of Japan and working on the development of OTEC systems, were represented at the UN conference for Small Island Developing States held in Mauritius. Although much interest was shown in utilising the Republic's ocean thermal resource, there has to date been no development.

Nauru

In 1981, the Tokyo Power Company built a 100 kW shore-based, closed cycle pilot plant on the island of Nauru. The plant achieved a net output of 31.5 kW during continuous operating tests. This plant very effectively proved the principle of OTEC in practical terms over an extended period, before being decommissioned.

Netherlands Antilles

A feasibility study carried out by Marine Structure Consultants of the Netherlands and funded by the Dutch Government for the Netherlands Antilles Government examined the competitiveness of a 10 MW floating OTEC plant. No development ensued.

New Caledonia

Ifremer (the French institute for research and exploitation of the sea) has re-examined a previous proposal to establish a test site for OTEC/DOWA in New Caledonia.

Northern Marianas

Using the islands' ocean thermal resource for power generation continues to be considered. A Memorandum of Understanding was signed in 2003 for the future development of a 10 MW plant, but to date the plan has not progressed.

Palau

In a plan to obviate a future need for diesel-generated electricity, Palau could utilise its ocean thermal resource to provide electricity supply.

In Spring 2001 the Government of Palau, Japan's Saga University and Xenesys Inc. (a Japanese private company) entered into an agreement that resulted in research and feasibility studies being undertaken for the identification of suitable sites for OTEC installations. Seven such sites were located on the biggest island in Palau (Babeldaob). It was stated that a pilot project would have a capacity of 3 000 kW that could ultimately reach 30 000 kW, an increase in excess of 50% from the current diesel-generated supply.

In addition to the production of power, the by-products of salt and fresh water could be used for organic farming.

It was reported that under the ACP-EU Partnership Agreement, the European Commission and the Government of Palau had drawn up a Country Strategy Paper and an Indicative Programme for the period 2002-2007. The EU was to provide financial assistance to Palau in order to expand the utilisation of renewable energy sources. However, to date no development has taken place.

Philippines

The aim of the New and Renewable Energy Program (NRE) of the Department of Energy (DOE) is to accelerate the development, promotion and commercialisation of new and renewable energy systems. The Philippines is well-endowed with a range of renewable energies and the Philippine Energy Plan (2005-2014) plans to utilise them in an effort to reduce fossil fuel consumption. To this end the DOE working with Japanese scientists has identified sixteen areas that could be suitable for the development of OTEC systems.

Puerto Rico

A resource assessment conducted in 1977 studied the potential for a nearshore OTEC plant. In 1997 a new evaluation concluded that a closed cycle, land-based OTEC plant of up to 10 MW was feasible, especially with the inclusion of DOWA. The headland of Punta Tuna on the south-east coast of the island satisfied the criteria for such a plant.

Saudi Arabia

It was reported in early 2003 that there had been high level governmental discussions between Japan and Saudi Arabia with a view to OTEC technology being utilised for water desalination and electricity production. To date, there has been no development.

Sri Lanka

Interest in OTEC and DOWA has been revived by the National Aquatic Resources Agency in Colombo, in the context of making use of Sri Lanka's EEZ, which is some 27 times its land area.

Three submarine canyons (Panadura, Dondra and Trincomalee) have been identified as highly suitable sites for OTEC plants and the production of electricity. The results of successful experiments conducted during 1994 were presented to the Government but political unrest in the area of Trincomalee has resulted in unsafe working conditions.

The Oceanography Division of the National Aquatic Resources Research & Development Agency (NARA) maintains contact with Japan's Institute of Ocean Energy (Saga University) and the Mitsui Corporation. Following the announcement in January 2007 of the establishment of an Alternative Energy Authority, it is hoped that in the future OTEC will play a significant role in Sri Lanka.

St. Lucia

In 1983, as a part of a commitment to develop alternative energy systems, the Government of St. Lucia welcomed the opportunity to be part of an OTEC initiative that included the design and construction of a 10 MW closed cycle floating OTEC demonstration plant off Soufriere. Hydrographic surveys in 1985 confirmed that the 1 000 m contour was less than 3 km from shore, with cold water in the volcanic canyon adjacent to Petit Piton and Gros Piton. This landfall was also close to the electrical grids. The surface temperature of the sea on that part of the west coast never falls below 25° C, reaching 27/28° C in summer.

The UK-designed plant was provided with a fully costed proposal by a merchant bank, which showed that with construction commencing in 1985, and operation from 1989, the OTEC plant would show a cost benefit over oil-fired plant from 1994, the higher capital cost of OTEC being balanced by the 'free fuel', whereas there were ongoing fuel costs for the diesel plant. However, the final decision was to go for a diesel plant, with the whole of the capital cost being funded by another country.

Taiwan, China

The seas off eastern Taiwan are considered to be highly favourable for OTEC development. Following preliminary studies during the 1980s, three nearshore sites were selected and the steeply shelving east coast was thought to be able to accommodate an onshore OTEC plant. However, only one site (Chang-Yuan) was deemed suitable for further investigation by the Institute of Oceanography.

In 1989, the Pacific International Center for High Technology Research in Hawaii prepared a development plan for the Taiwanese Multiple Product Ocean Thermal Energy Conversion Project (MPOP). The intention of the MPOP was to construct a 5 MW closed cycle pilot plant for generating power and also the development of mariculture, desalinated water, air conditioning, refrigeration and agriculture. It was thought that the operating data obtained from the pilot plant could be used in the building of a 50-100 MW commercial plant. In 1993 it was assumed that 6 years would be required for site preparation and 5 years for construction, with the plant having a 25-year life cycle.

During the 1990s the concept of MPOP changed to a Master OTEC Plan for R.O.C. (MOPR), with the objective of ultimately establishing eight 400 MW floating OTEC power plants.

With its positive interest, Taiwan was the initiator, in 1989, of the International OTEC/DOWA Association (IOA). Until around 2004 a permanent Taiwanese secretariat worked to ensure a higher international profile for OTEC/DOWA but both the organisation and plans for OTEC within the country have, at present, somewhat stagnated.

United States of America

Hawaii remains the focus of US activity in OTEC/DOWA, primarily through work carried out at the Natural Energy Laboratory of Hawaii (NELHA) facility at Keahole Point.

In 1979 'Mini-OTEC', a 50 kW closed cycle demonstration plant, was set up at NELHA. It was the world's first net power producing OTEC plant, installed on a converted US Navy barge moored 2 km offshore: it produced 10-17 kW of net electric power.

In 1980 the Department of Energy constructed a test facility (OTEC-1) for closed cycle OTEC heat exchangers on a converted US Navy tanker. It was not designed to generate electricity.

In the early 1980s a 40 MW OTEC pilot plant was designed. It was to be sited on an artificial island off the Hawaiian coast. However, funding was not forthcoming and the plant was not constructed.

An experimental 210 kW (gross electrical) open cycle OTEC plant was designed and operated by the Pacific International Center for High Technology Research (PICHTR) at Keahole Point. It produced a record level of 50 kW of net power in May 1993, thus exceeding the 40 kW net produced by a Japanese OTEC plant in 1982. The plant operated from 1993 until 1998 and its primary purpose was to gather the necessary data to facilitate the development of a commercial-scale design. Following the experiments, the plant was demolished in January 1999.

A further PICHTR experiment at NELHA employed a closed cycle plant to test specially developed aluminium heat exchangers. It used the (refurbished) turbine from 'Mini-OTEC' to produce 50 kW gross power. During initial operation in May 1996, corrosion leaks developed in the heat exchanger modules; the plant had to be shut down and the units re-manufactured. From October 1998, when the new units were received until end-1999 - the end of the project - data were collected on the heat exchange and flow efficiencies of the heat exchangers and thus on the economic viability of competing types of heat exchangers.

In addition to research into ocean thermal energy, NELHA has established an ocean science and technology park at Keahole Point. Cold deep seawater is pumped to the surface and utilised for the production of energy, air-conditioning, desalination, fish farming, agriculture, etc.

NELHA has reported that during fiscal year 2006 a letter of understanding had been signed with Ocean Engineering & Energy Systems (OCEES) of Honolulu to construct an OTEC plant utilising the 55 inch pre-existing cold water pipes. At the beginning of 2007 negotiations were continuing, with an expected operational date of 2009 for the 1-1.2 MW plant.

Virgin Islands

The island of St. Croix has been found to be a suitable site for the development of OTEC-produced electricity and desalinated water.

In the early 1990s an agreement was drawn up between the US company GenOtec and the Virgin Islands Water and Power Authority (WAPA). The plan was to obtain 5 MW of OTEC-produced electricity and 1.5 million gallons/day of desalinated water from a land-based, closed cycle OTEC plant. Additionally, various mariculture industries were planned. The project did not come to fruition.

Abbreviations and Acronyms

10^3	kilo (k)
10^6	mega (M)
10^9	giga (G)
10^{12}	tera (T)
10^{15}	peta (P)
10^{18}	exa (E)
10^{21}	zetta (Z)
ABWR	advanced boiling water reactor
AC	alternating current
AHWR	advanced heavy water reactor
API	American Petroleum Institute
APR	advanced pressurised reactor
APWR	advanced pressurised water reactor
b/d	barrels per day
bbl	barrel
bcf	billion cubic feet
bcm	billion cubic metres
BGR	Bundesanstalt für Geowissenschaften und Rohstoffe
billion	10^9
BIPV	building integrated PV
BNPP	buoyant nuclear power plant
boe	barrel of oil equivalent
BOO	build, own, operate
BOT	build, operate, transfer
bpsd	barrels per stream-day
bscf	billion standard cubic feet
Btu	British thermal unit
BWR	boiling light-water-cooled and moderated reactor
C	Celsius
CBM	coal-bed methane
cf	cubic feet
CHP	combined heat and power
CIS	Commonwealth of Independent States
cm	centimetre
CMM	coal mine methane
CNG	compressed natural gas
CO_{2e}	carbon dioxide equivalent
COP3	Conference of the Parties III, Kyoto 1997
cP	centipoise
CSP	centralised solar power
d	day
DC	direct current
DHW	domestic hot water
DOWA	deep ocean water applications
ECE	Economic Commission for Europe
EIA	US Energy Information Administration / environmental impact assessment
EOR	enhanced oil recovery
EPR	European pressurised water reactor
ETBE	ethyl tertiary butyl ether
F	Fahrenheit
FAO	UN Food and Agriculture Organization
FBR	fast breeder reactor
FID	final investment decision
FSU	former Soviet Union
ft	feet
g	gram
gC	grams carbon
GEF	Global Environment Facility
GHG	greenhouse gas
GTL	gas to liquids
GTW	gas to wire
GW_e	gigawatt electricity

GWh	gigawatt hour
h	hour
ha	hectare
HDR	hot dry rocks
hm^3	cubic hectometre
HPP	hydro power plant
HTR	high temperature reactor
Hz	hertz
IAEA	International Atomic Energy Agency
IBRD	International Bank for Reconstruction and Development
IEA	International Energy Agency
IIASA	International Institute for Applied Systems Analysis
IMF	International Monetary Fund
IMO	International Maritime Organization
IPP	independent power producer
IPS	International Peat Society
J	joule
kcal	kilocalorie
kg	kilogram
km	kilometre
km^2	square kilometre
kPa	kilopascal
ktoe	thousand tonnes of oil equivalent
kV	kilovolt
kW_e	kilowatt electricity
kWh	kilowatt hour
kW_p	kilowatt peak
kW_t	kilowatt thermal
lb	pound (weight)
LNG	liquefied natural gas
LPG	liquefied petroleum gas

l/s	litres per second
l/t	litres per tonne
LWGR	light-water-cooled, graphite-moderated reactor
LWR	light water reactor
m	metre
m/s	metres per second
m^2	square metre
m^3	cubic metre
mb	millibar
Mcal	megacalorie
MJ	Megajoule
Ml	megalitre
mm	millimetre
MOU	memorandum of understanding
MPa	megapascal
mPa s	millipascal second
MSW	municipal solid waste
mt	million tonnes
mtpa	million tonnes per annum
mtoe	million tonnes of oil equivalent
MW	megawatt
MW_e	megawatt electricity
MWh	megawatt hour
MW_p	megawatt peak
MW_t	megawatt thermal
N	negligible
NEA	Nuclear Energy Agency
NGLs	natural gas liquids
NGO	non governmental organisation
Nm^3	normal cubic metre
NPP	nuclear power plant / net primary productivity

OAPEC	Organisation of Arab Petroleum Exporting Countries
OECD	Organisation for Economic Co-operation and Development
OPEC	Organisation of the Petroleum Exporting Countries
OTEC	ocean thermal energy conversion
OWC	oscillating water column
p.a.	per annum
PBMR	pebble bed modular reactor
PDO	plan for development and operation
PFBR	prototype fast breeder reactor
PHWR	pressurised heavy-water-moderated and cooled reactor
ppm	parts per million
ppmv	parts per million by volume
psia	pounds per square inch, absolute
PV	photovoltaic
PWR	pressurised light-water-moderated and cooled reactor
RBMK	reaktor bolchoi mochtchnosti kanalni
R&D	research and development
RD&D	research, development and demonstration
R/P	reserves/production
rpm	revolutions per minute
SER	Survey of Energy Resources
SHS	solar home system
SWH	solar water heating
t	tonne (metric ton)
tb/d	thousand barrels per day
tC	tonnes carbon
tce	tonne of coal equivalent
tcf	trillion cubic feet

tcm	trillion cubic metres
toe	tonne of oil equivalent
tpa	tonnes per annum
TPP	tidal power plant
tpsd	tonnes per stream day
tscf	trillion standard cubic feet
trillion	10^{12}
ttoe	thousand tonnes of oil equivalent
tU	tonnes of uranium
TWh	terawatt hour
U	uranium
U_3O_8	uranium oxide
UN	United Nations
UNDP	United Nations Development Programme
vol	volume
W	watt
WEC	World Energy Council
W_p	watts peak
WPP	wind power plant
wt	weight
WTO	World Trade Organization
WWER	water-cooled water-moderated power reactor
yr	year
—	unknown or zero
~	approximately
<	less than
>	greater than
≥	greater than or equal to

Conversion Factors and Energy Equivalents

Basic Energy Units

1 joule (J) = 0.2388 cal

1 calorie (cal) = 4.1868 J

(1 British thermal unit [Btu] = 1.055 kJ = 0.252 kcal)

WEC Standard Energy Units

1 tonne of oil equivalent (toe) = 42 GJ (net calorific value) = 10 034 Mcal

1 tonne of coal equivalent (tce) = 29.3 GJ (net calorific value) = 7 000 Mcal

Note: the tonne of oil equivalent currently employed by the International Energy Agency and the United Nations Statistics Division is defined as 10^7 kilocalories, net calorific value (equivalent to 41.868 GJ).

Volumetric Equivalents

1 barrel = 42 US gallons = approx. 159 litres
1 cubic metre = 35.315 cubic feet = 6.2898 barrels

Electricity

1 kWh of electricity output = 3.6 MJ = approx. 860 kcal

Representative Average Conversion Factors

1 tonne of crude oil = approx. 7.3 barrels

1 tonne of natural gas liquids = 45 GJ (net calorific value)

1 000 standard cubic metres of natural gas = 36 GJ (net calorific value)

1 tonne of uranium (light-water reactors, open cycle) = 10 000–16 000 toe

1 tonne of peat = 0.2275 toe

1 tonne of fuel wood = 0.3215 toe

1 kWh (primary energy equivalent) = 9.36 MJ = approx. 2 236 Mcal

Note: actual values vary by country and over time.

Because of rounding, some totals may not agree exactly with the sum of their component parts.

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World Energy Council
Regency House 1-4 Warwick Street
London W1B 5LT United Kingdom
T (+44) 20 7734 5996
F (+44) 20 7734 5926
E info@worldenergy org
www worldenergy org

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