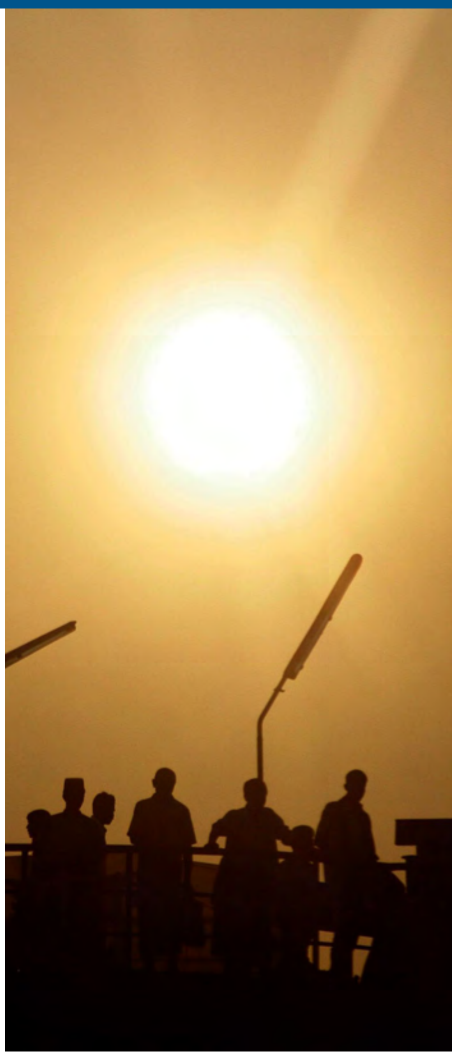
WORLD ENERGY COUNCIL
CONSEIL MONDIAL DE L'ÉNERGIE
For sustainable energy.

World Energy Resources

2013 Survey

WORLD ENERGY COUNCIL
CONSEIL MONDIAL DE L'ÉNERGIE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Foreword

As energy is the main 'fuel' for social and economic development, and since energy-related activities have significant environmental impacts, it is important for decision-makers to have access to reliable and accurate data in an user-friendly format. WEC has for decades been a pioneer in the field of energy resources and every three years publishes its flagship report Survey of Energy Resources (SER) which is released during the World Energy Congress. *World Energy Resources* (WER) 2013 is the new title of this publication and in fact is the 23rd edition for the Survey of Energy Resources. The survey is recognised worldwide as the premier source of information on global energy resources. Its reputation and value since the first edition in 1933 rest on two main factors: the study presents unbiased data and facts from an independent and impartial organisation, and the second factor is the sheer amount of resource and other key energy data together with analysis of technological, economic and environmental aspects assessed on global, regional and country levels.

The 2013 report covers all fossil resources (coal, oil, both conventional and unconventional and gas, both conventional and unconventional), and the main renewable and transitional resources: peat, nuclear and uranium, hydro power, biofuels and waste, wind, solar, geothermal and marine energies. This edition also discusses energy efficiency as a strategic 'energy resource' because every unit of energy saved – a so-called 'negajoule' – is less expensive than producing the same amount of energy.

Each of the 12 chapters is organised in three sections: an introduction covering technical, economic and market issues; detailed tables with global, regional and country data for proved reserves and production followed by country notes. The information comes from a variety of international sources, including the contributions of resource experts and data from the WEC Members Committees. The new structure of the energy sector post-market liberalisation and privatisation has made it difficult to access data and other information as companies and other organisations consider the majority of data as "confidential and commercially sensitive."

An extra feature of this 2013 survey is a review of the energy resources evolution over the past 20 years. The results of the current WEC work are compared to the projections made by the WEC in its milestone report, *Energy for Tomorrow's World*, published in 1993. The 2013 Summary also looks at the main factors that have influenced the development of the global energy sector the most over the past two decades.

The world around us has changed significantly over the past 20 years. The following principal drivers have been shaping energy supply and use:

- sharp increase in the price of oil since 2001 after 15 years of moderate oil prices
- financial crisis and slow economic growth with drastic reduction in energy consumption in large economies
- shale gas in North America
- Fukushima Daiichi nuclear accident
- The volatile political situation in the energy supplying countries in the Middle East and North Africa, "The Arab Spring"
- lack of global agreement on climate change mitigation
- collapse of CO_2 prices in the European Emissions Trading System
- exponential growth in renewables, in particular in Europe due to generous subsidies for producers which can become a problem instead of an opportunity
- deployment of 'smart' technologies
- energy efficiency potential still remaining untapped
- growing public concerns about new infrastructure projects, including energy projects and their impact on political decision-making process

I am grateful to all those who have helped to produce the 2013 report, including Study Group Members, WEC Member Committees, leading energy institutions and individual experts. My special thanks for the coordination, guidance and management to the WEC Secretariat with excellent and highly professional contributions from Elena Nekhaev, Director of Programmes, and Paul Benfield, Senior Project Manager.

Alessandro Clerici
Executive Chair, WEC World Energy Resources

Chair
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Italy

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Petroleo Brasileiro S.A.
Brazil

Study Group Members

Bongani Thusi
Ministry of Natural Resources and Energy – Swaziland
Swaziland

Brigitte Svarich
Energy Council of Canada
Canada

Fabian Melon
PricewaterhouseCoopers (PwC)
Germany

Fabio Emiro Sierra Vargas
National University of Colombia
Colombia

Firouzeh Amini
Iran

Gerardo Rabinovich
Argentina

Greg Schmidt
Energy Council of Canada
Canada

Iulian Iancu
Government of Romania
Romania

Jean-Eudes Moncomble
France

Jose Antonio Tagle
IBERDROLA
Spain

Klaus Hammes
Swedish Energy Agency
Sweden

Luca Lo Re
BNL Clean Energy AG
France

Marc Florette
GDF SUEZ
France

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Suncor Energy Inc.
Canada

Michael W. Howard
EPRI
United States of America

Mostafa Tavanpoor Paveh
Iran

Pasquale Monti
Enel GreenPower
Italy

Paul Cheliak
Canadian Gas Association
Canada

Roland Luebke
German Coal Association
Germany

Sandra Scalari
ENEL S.p.A.
Italy

Sylvain Hercberg
EDF Energy plc
France

Tiina Koljonen
Technical Research Centre of Finland (VTT)
Finland

Uwe Maaßen
Deutscher Braunkohlen Industrie Verein e.V.
Germany

Volker Breisig
PricewaterhouseCoopers (PwC)
Germany

Wayne Chodzicki
KPMG LLP
Canada

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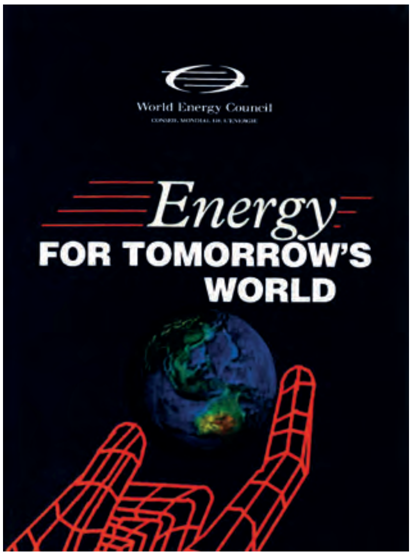
Introduction

This summary of the World Energy Resources report is primarily based on the results of the WEC's work programme since the World Energy Congress in Montreal in 2010. Focusing on energy resources, the summary also takes into account relevant insights from WEC Member Committees and other studies and programmes, such as Energy Efficiency Policies and Technologies, Performance of Generating Plant, Cost of Energy Technologies conducted together with Bloomberg New Energy Finance, Energy Trilemma, World Energy Scenarios to 2050 and other reports (www.worldenergy.org/publications).

The World Energy Council has been producing the Survey of Energy Resources report since 1933. This 23rd edition of the Survey will be published under the new title World Energy Resources (WER). Over decades the report has been the most widely recognised and authoritative publication on global energy resources and millions of copies of the report have been downloaded from the WEC website. The survey covers:



'The WEC Report presents energy issues of global importance in a responsible and balanced manner, providing a most useful contribution to the debate on these topics.'

John S Jennings, Managing Director, Royal Dutch Shell/Shell Group

'This report is a major statement that not only signals a broadening of perspectives of the global energy community, which the WEC effectively represents, but also a landmark in addressing issues of sustainable development.'

RK Pachauri, Director General, The Energy and Resources Institute (TERI) and Chair of the Intergovernmental Panel on Climate Change (IPCC)

An extra feature of the 2013 report presents an historical perspective on energy resources and a few important energy issues that are based on the comparative analysis of statistics, findings and assumptions and their evolution over the past 20 years. The results of the report are compared to the projections made by the WEC in its milestone report *Energy for Tomorrow's World* published in 1993. That report was produced with significant support from private companies from WEC Member Committees, public utilities, governments, academia and prominent individuals, altogether more than 500 experts representing nearly 100 countries including all of the major energy production and consumption markets. *Energy for Tomorrow's World* firmly put WEC on the map of leading global energy bodies.

2013 is a good moment to stop and look back, particularly since this year WEC is celebrating its 90th birthday. If one had to choose from a number of assumptions which over the past two decades had influenced the development of the global energy sector most, the majority would perhaps pick the environment and especially climate change. Renewable energy would also be at the top of the list of decisive factors. The energy sector looked different until the UN Framework Convention on Climate Change was signed in Rio de Janeiro in 1992. Since then, sustainable development has become one of the principal drivers shaping the energy future of the world.

The energy sector has long lead times and therefore any long-term strategy should be based on sound information and data. Detailed resource data, selected cost data and a technology overview in the main WER report provide an excellent foundation for assessing different energy options based on factual information supplied by the WEC members from all over the world.

What has changed?

The world around us has changed significantly over the past 20 years. Technology has become one of the main drivers of economic and social development. The rapid advancement of Information Technology (IT) all over the world has transformed not only the way we think, but also the way we act. All aspects of human life have been affected by IT and the Internet, in particular. Needless to say that practically all technologies run on electricity and therefore the share of electricity is increasing rapidly, faster than Total Primary Energy Supply (TPES).

Table 1: Key indicators for 1993, 2011 and 2020

Source: 1993, 2020 figures from Energy for Tomorrow's World (WEC, 1995). 2011 figures from World Energy Resources (WEC, 2013). Other renewables 2020 figure from World Energy Scenarios report (WEC, 2013)

	1993	2011	2020	% Growth 1993–2011
Population, billion	5.5	7	8.1	27%
GDP				
Trillion USD	25	70	65	180%
TPES Mtoe	9 532	14 092	17 208	48%
Coal Mt	4 474	7 520	10 108	68%
Oil Mt	3 179	3 973	4 594	25%
Natural Gas bcm	2 176	3 518	4 049	62%
Nuclear TWh	2 106	2 386	3 761	13%
Hydro Power TWh	2 286	2 767	3 826	21%
Biomass Mtoe	1 036	1 277	1 323	23%
Other renewables* TWh	44	515	1 999	n/a
Electricity Production/year				
Total TWh	12 607	22 202	23 000	76%
Per capita MWh	2	3	3	52%
CO_2 emissions/year				
Total CO_2 Gt	21	30	42	44%
Per capita tonne CO_2	4	4	n/a	11%
Energy intensity koe, 2005 USD	0.24	0.19	n/a	-21%

* Includes figures for all renewables, except Hydro

Population growth has always been and will remain one of the key drivers of energy demand, along with economic and social development. While global population has increased by over 1.5 billion over the past two decades, the overall rate of population growth has been slowing down. The number of people without access to commercial energy has reduced slightly, and the latest estimate from the World Bank indicates that it is 1.2 billion people.

The only renewable energy resources for which projections were made in 1993 were hydro power and biomass. The contribution of renewables was not very significant in those days, and the rest of the renewables were not taken into consideration individually, but combined into one group called Other Renewables. For comparability, the same resources are included under this heading for 2011. They are however, presented separately in the full World Energy Resources 2013 report.

Table 1 shows the actual values for a number of indicators recorded in 1993, the status of these indicators in 2011 and the projections for 2020 made in *Energy for Tomorrow's World*, High-Growth Scenario A to 2020. The comparison demonstrates that future developments are often underestimated. Even the highest projections made 20 years ago, fall far below the reality. What does it mean? It means that the demand for energy might grow significantly faster than expected, and if properly managed, energy resources and technologies should be available to meet this demand.

The changes in the energy industry over the past 20 years have been significant. Looking at the results of the present 2013 WEC World Energy Resources survey, it becomes evident that there are more energy resources in the world today than ever before. However, the increase in resource assessments in 2013, in many cases, can be attributed to new, more efficient technologies. As the international definition used by the United Nations stipulates:

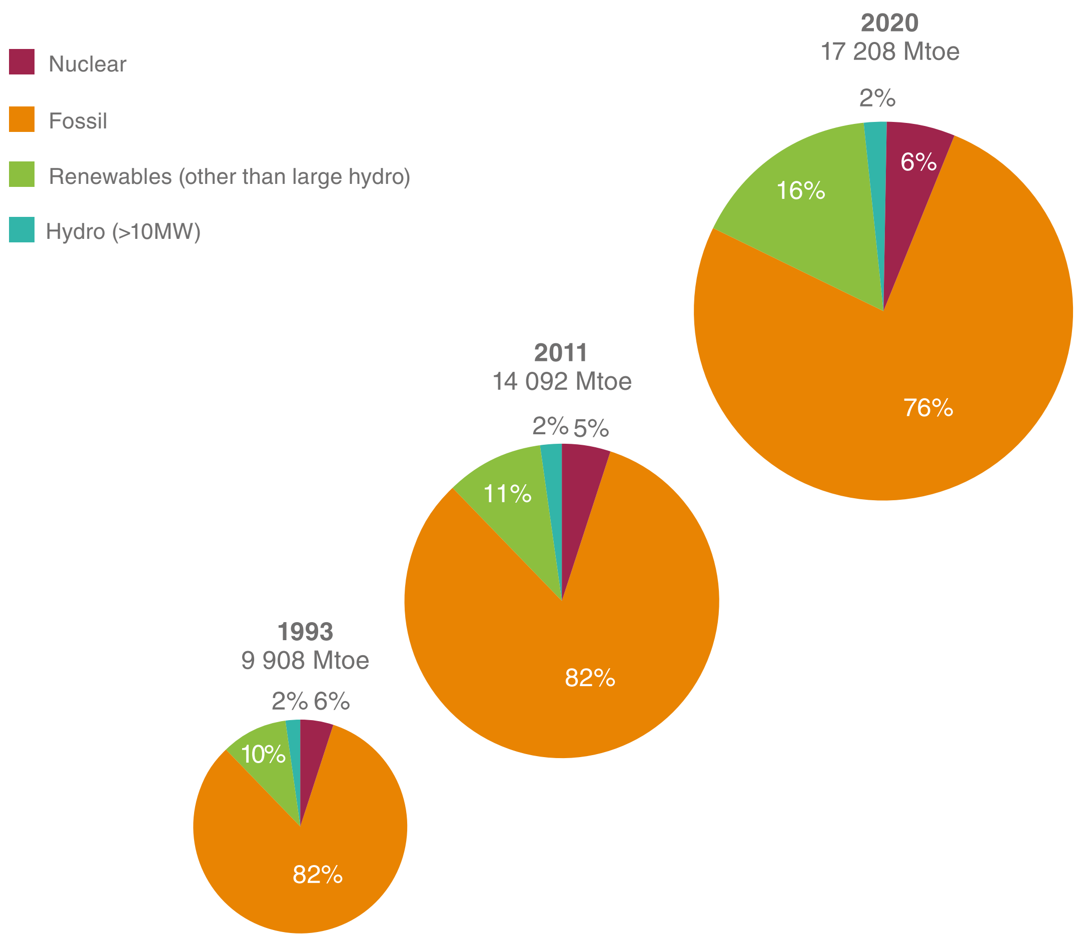
> "Proved recoverable reserves are the quantity within the proved amount in place that can be recovered in the future under present and expected local economic conditions with existing available technology."

The recent shale gas developments in the United States clearly demonstrate this concept and the role of technologies. The enormous resources of shale gas have always been there, but it is only since the introduction of hydraulic-fracturing technology at an economically attractive price, that the gas market revolution has become a reality.

The general message emerging from the 2013 survey confirms that the main fossil fuels: coal, oil and natural gas are plentiful and will last for decades.

Total Primary Energy Supply by resource 1993, 2011 and 2013

Source: WEC Survey of Energy Resources 1995, World Energy Resources 2013 and WEC World Energy Scenarios to 2050

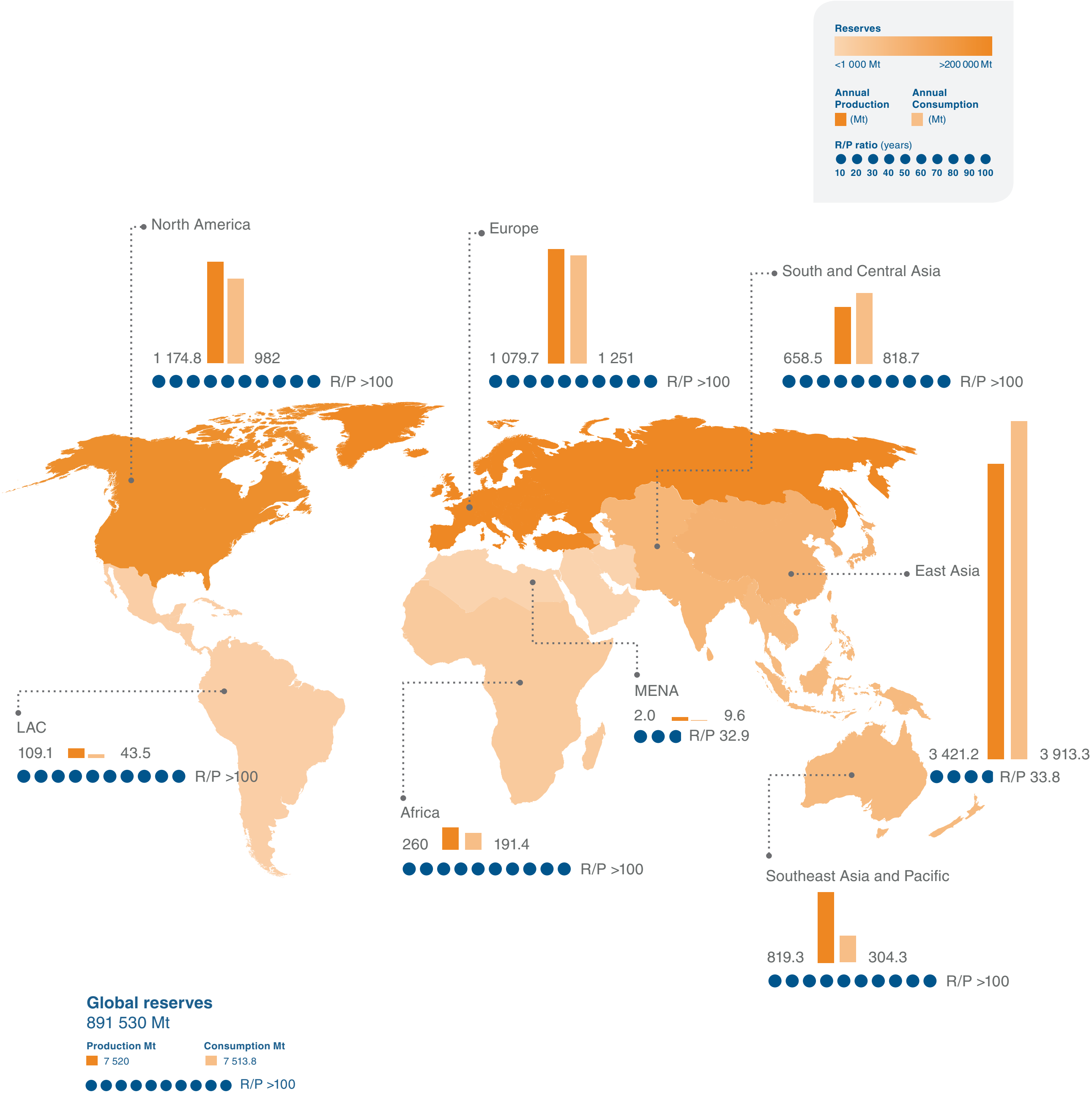


The supply and use of energy have powerful economic, social and environmental impacts. Not all energy is supplied on a commercial basis. Fuels, such as fuelwood or traditional biomass are largely non-commercial. Fuelwood is playing a leading role in the developing countries, where it is widely used for heating and cooking.

Universal access to commercial energy still remains a target for the future. In many countries, especially in Africa and Asia, the pace of electrification lags far behind the growing demand. It is imperative to address this major challenge without further delays, in particular taking into account the impact access to electricity has on peoples' lives and well-being, economic growth and social development, including the provision of basic social services, such as health and education.

Establishment of energy infrastructure in the least developed countries will need a major effort on behalf of the global energy community. It will also require political, legal and institutional structures, which today do not exist. Rising energy demand, declining public investment and the evolving role of the multilateral financial institutions need increased efforts by governments to change their roles in order to create an enabling business environment to attract private investment, both domestic and international.

Coal



Despite its poor environmental credentials, coal remains a crucial contributor to energy supply in many countries. Coal is the most wide-spread fossil fuel around the world, and more than 75 countries have coal deposits. The current share of coal in global power generation is over 40%, but it is expected to decrease in the coming years, while the actual coal consumption in absolute terms will grow. Although countries in Europe, and to some extent North America, are trying to shift their consumption to alternative sources of energy, any reductions are more than offset by the large developing economies, primarily in Asia, which are powered by coal and have significant coal reserves. China alone now uses as much coal as the rest of the world.

The continuing popularity of coal becomes particularly obvious when compared to the current production figures with those from 20 years ago. While the global reserves of coal have decreased by 14% between 1993 and 2011, the production has gone up by 68% over the same time period. Compared to the 2010 survey, the most recent data shows that the proved coal reserves have increased by 1% and production by 16%. The future of coal depends primarily on the advance of clean coal technologies to mitigate environmental risk factors, CO_2 emissions, in particular. Today Carbon Capture Utilisation and Storage (CCS/CCUS) is the only large-scale technology which could make a significant impact on the emissions from fossil fuels. It is, however, still at the pilot stage and its future is uncertain, mainly because of the high costs and efficiency penalty.

Coal is playing an important role in delivering energy access, because it is widely available, safe, reliable and relatively low cost. One of the major challenges facing the world at present is that approximately 1.2 billion people live without any access to modern energy services. Access to energy is a fundamental pre-requisite for modern life and a key tool in eradicating extreme poverty across the globe.

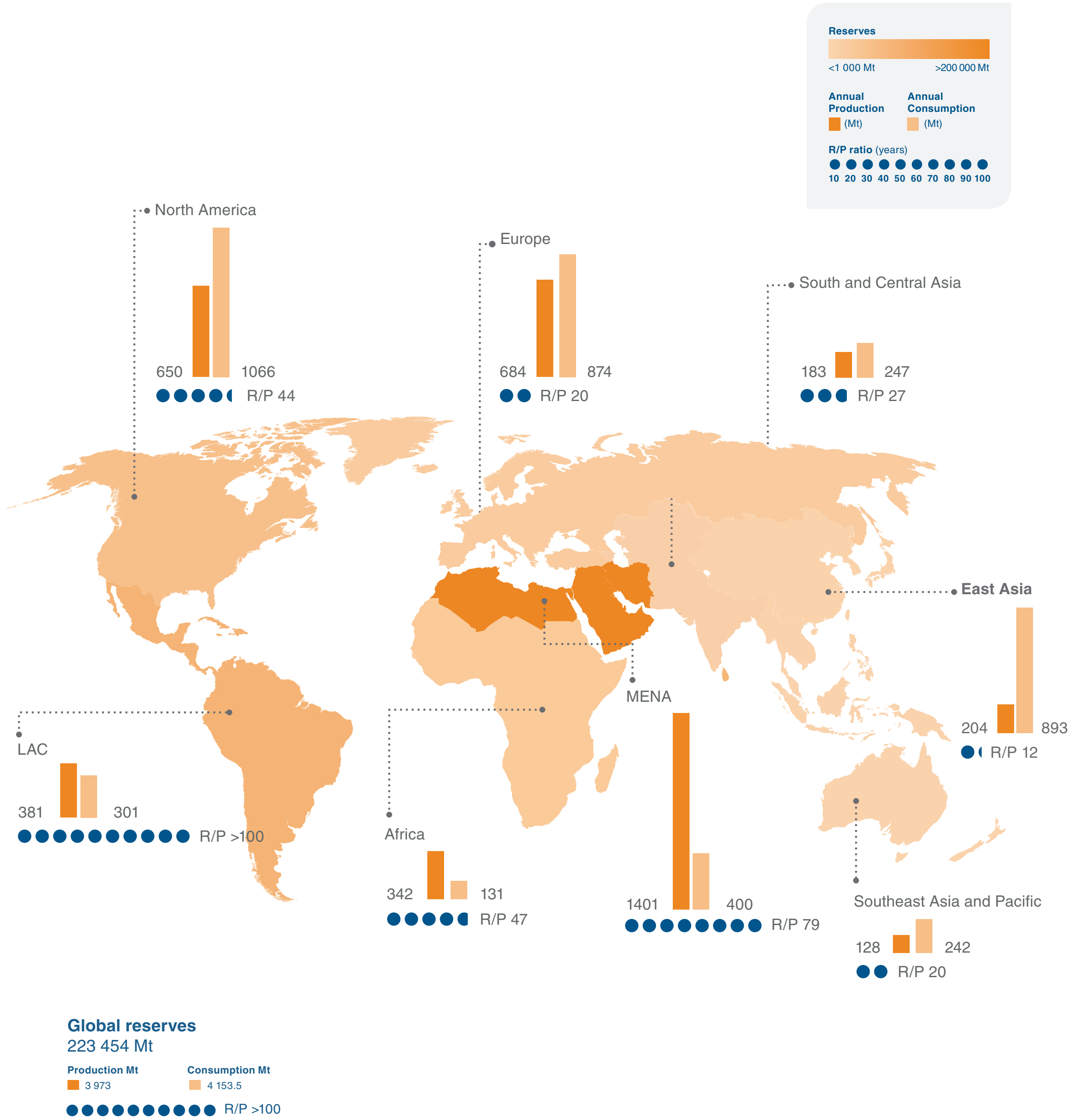
Coal resources exist in many developing countries, and this report demonstrates that many countries with electricity challenges, particularly those in Asia and southern Africa, are able to access coal resources in an affordable and secure way to fuel the growth in their electricity supply. Coal will therefore play a major role in supporting the development of base-load electricity where it is most needed. Coal-fired electricity will be fed into national grids and it will bring energy access to millions, thus facilitating economic growth in the developing world.

Coal reserves: top 5 countries

	Reserves (Mt)		Production (Mt)		2011 R/P
Country	**2011**	**1993**	**2011**	**1993**	**years**
United States of America	237 295	168 391	1 092	858	> 100
Russian Federation	157 010	168 700	327	304	> 100
China	114 500	80 150	3 384	1 150	34
Australia	76 400	63 658	398	224	> 100
India	60 600	48 963	516	263	> 100
Rest of World	245 725	501 748	1 805	1 675	> 100
Global total	**891 530**	**1 031 610**	**7 520**	**4 474**	**> 100**

Benefits	Drawbacks
Wide geographic distribution	High emissions of CO_2, particulates and other pollutants
Stable and predictable costs	Not suitable for peaking generation units
New technologies for coal improve efficiency and environmental performance	CCS/CCUS have negative impact on thermal plant efficiency

Oil



The oil crisis in the 1970s and 1980s resulted in long queues outside petrol stations and the sky-rocketing price of oil. In the following years, heated discussions about "peak oil" were based on the expectation of the world running out of oil within a few decades. Now in 2013, the peak oil issue is not making headlines any longer, however since oil is a finite resource this issue will return in the future. Global oil reserves are almost 60% larger today than 20 years ago, and production of oil has gone up by 25%.

If the unconventional oil resources, including oil shale, oil sands, extra heavy oil and natural bitumen are taken into account, the global oil reserves will be four times larger than the current conventional reserves. Oil still remains the premier energy resource with a wide range of possible applications. Its main use however, will be shifting towards transport and the petrochemical sector. In future oil's position at the top of the energy ladder will face a strong challenge from other fuels such as natural gas. The oil resource assessments have increased steadily between 2000 and 2009, and about a half of this increase is due to the reclassification of the Canadian oil sands and the revisions undertaken in major OPEC countries: Iran, Venezuela and Qatar. Compared to the 2010 survey, the proved oil reserves increased by 37% and production by 1%.

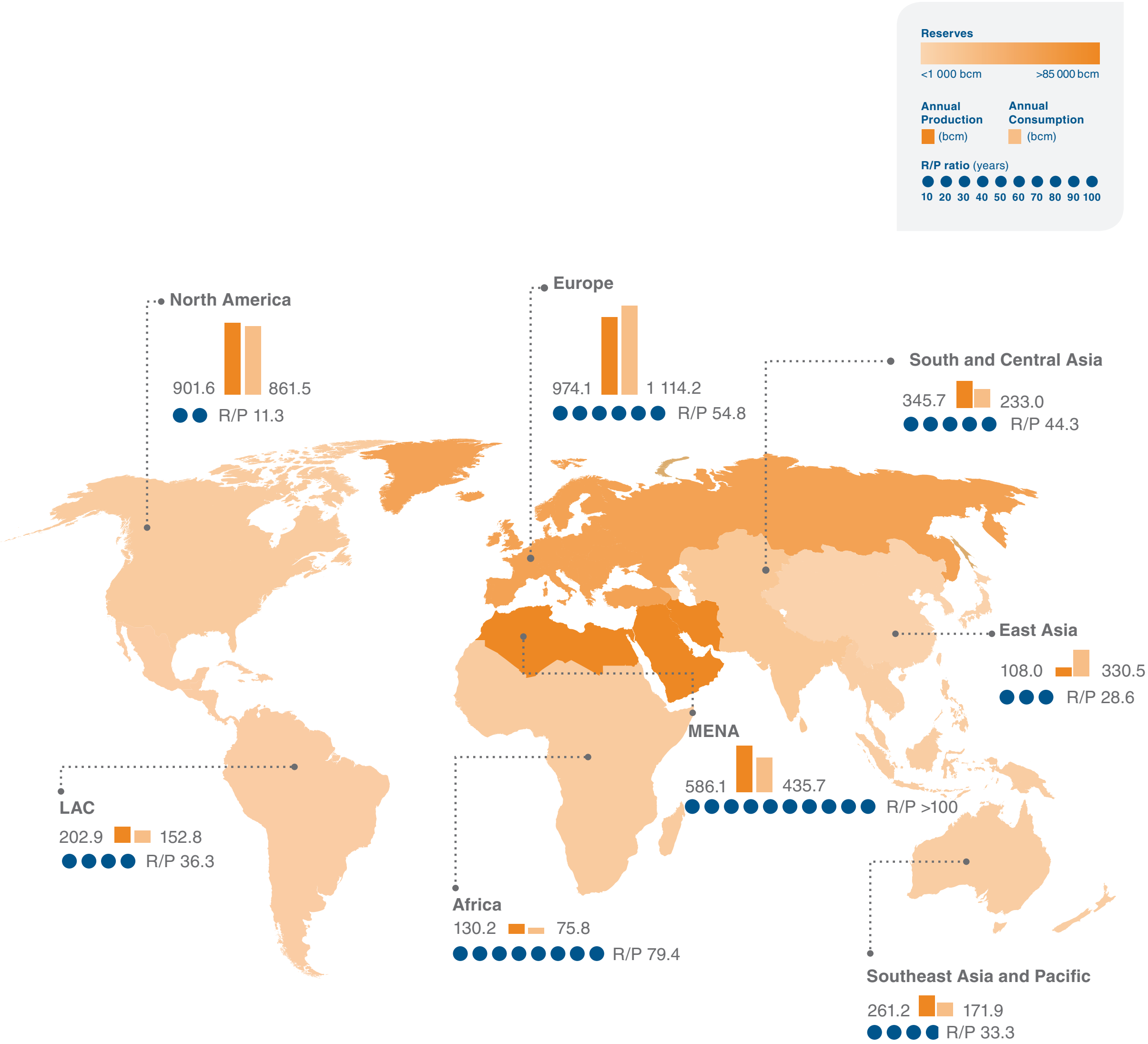
Oil is a mature global industry which offers the market participants opportunities for good economic returns. The balance between returns on capital and host countries' interests is a delicate matter. A number of countries, for political reasons, have limited the access of international companies.

Crude oil reserves: top 5 countries

	Reserves (Mt)		Production (Mt)		R/P
Country	**2011**	**1993**	**2011**	**1993**	**years**
Venezuela	40 450	9 842	155	129	> 100
Saudi Arabia	36 500	35 620	526	422	69
Canada	23 598	758	170	91	> 100
Iran	21 359	12 700	222	171	96
Iraq	19 300	13 417	134	29	> 100
Rest of World	82 247	68 339	2 766	2 338	30
Global total	**223 454**	**140 676**	**3 973**	**3 179**	**56**

Benefits	Drawbacks
Currently indispensable for road transport and petrochemical industries	High price volatility
Leading tradable commodity	Geopolitical tensions related to areas of greatest reserves
Flexible, easy to transport fuel	Market dominated by leading oil producers (OPEC and large NOCs)

Natural gas



Global reserves
209 741.9 bcm

Production 3 518 bcm

Consumption 3 375.5 bcm

R/P 55

Natural gas is yet another fossil fuel resource that will continue making significant contribution to the world energy economy. The cleanest of all fossil-based fuels, natural gas is plentiful and flexible. It is increasingly used in the most efficient power generation technologies, such as, Combined Cycle Gas Turbine (CCGT) with conversion efficiencies of about 60%. The reserves of conventional natural gas have grown by 36% over the past two decades and its production by 61%. Compared to the 2010 survey, the proved natural gas reserves have grown by 3% and production by 15%.

The exploration, development and transport of gas usually requires significant upfront investment. Close coordination between investment in the gas and power infrastructure is necessary.

In its search for secure, sustainable and affordable supplies of energy, the world is turning its attention to unconventional energy resources. Shale gas is one of them. It has turned upside down the North-American gas markets, and is making significant strides in other regions. The emergence of shale gas as a potentially major energy source can have serious strategic implications for geopolitics and the energy industry.

Natural gas reserves: top 5 countries

	Reserves (bcm)		Production (bcm)		R/P
Country	2011	1993	2011	1993	years
Russian Federation	47 750	48 160	670	604	71
Iran	33 790	20 659	150	27	> 100
Qatar	25 200	7 079	117	14	> 100
Turkmenistan	25 213	2 860	75	57	> 100
Saudi Arabia	8 028	5 260	99	36	81
Rest of World	69 761	57 317	2 407	1 438	22
Global Totals	**209 742**	**141 335**	**3 518**	**2 176**	**55**

Benefits	Drawbacks
Cleanest of fossil fuels	Fields increasingly off-shore and in remote areas
Flexible and efficient fuel for power generation	High upfront investment requirement for transport and distribution system
Increasing proved reserves (reassessments and shale gas)	Increasingly long supply routes and high cost of infrastructure

Uranium and Nuclear

The nuclear industry has a relatively short history: the first nuclear reactor was commissioned in 1954. Uranium is the main source of fuel for nuclear reactors. Worldwide output of uranium has recently been on the rise after a long period of declining production caused by oversupply following nuclear disarmament. The present survey shows that total identified uranium resources have grown by 12.5% since 2008 and they are sufficient for over 100 years of supply based on current requirements.

Total nuclear electricity production has been growing during the past two decades and reached an annual output of about 2 600TWh by the mid-2000s, although the three major nuclear accidents have slowed down or even reversed its growth in some countries. The nuclear share of total global electricity production reached its peak of 17% by the late 1980s, but since then it has been falling and dropped to 13.5% in 2012. In absolute terms, the nuclear output remains broadly at the same level as before, but its relative share in power generation has decreased, mainly due to Fukushima nuclear accident.

Japan used to be one of the countries with a high share of nuclear (30%) in its electricity mix and high production volumes. Today, Japan has only two of its 54 reactors in operation. The rising costs of nuclear installations and lengthy approval times required for new construction have had an impact on the nuclear industry. The slowdown has not been global, as new countries, primarily in the rapidly developing economies in the Middle East and Asia, are going ahead with their plans to establish a nuclear industry.

Nuclear Power: top 5 countries 2011

Nuclear	Installed Capacity (MW)		Actual Generation (GWh)	
Country	**2011**	**1993**	**2011**	**1993**
United States of America	98 903	99 041	799 000	610 000
France	63 130	59 032	415 480	350 000
Japan	38 009	38 038	162 900	246 000
Russian Federation	23 643	19 843	122 130	119 000
Korea (Republic)	20 718	7 615	98 616	58 100
Rest of World	119 675	116 726	787 777	722 900
Global Total	**364 078**	**340 295**	**2 385 903**	**2 106 000**

Benefits	Drawbacks
High efficiency	High CAPEX and rising compliance costs
Moderate and predictable cost of electricity over the service life	Public concerns about operation and final waste disposal
No CO_2 during life cycle	Liabilities in case of nuclear accident

Hydro Power

Hydro power provides a significant amount of energy throughout the world and is present in more than 100 countries, contributing approximately 15% of the global electricity production. The top 5 largest markets for hydro power in terms of capacity are Brazil, Canada, China, Russia and the United States of America. China significantly exceeds the others, representing 24% of global installed capacity. In several other countries, hydro power accounts for over 50% of all electricity generation, including Iceland, Nepal and Mozambique for example. During 2012, an estimated 27–30GW of new hydro power and 2–3GW of pumped storage capacity was commissioned.

In many cases, the growth in hydro power was facilitated by the lavish renewable energy support policies and CO_2 penalites. Over the past two decades the total global installed hydro power capacity has increased by 55%, while the actual generation by 21%. Since the last survey, the global installed hydro power capacity has increased by 8%, but the total electricity produced dropped by 14%, mainly due to water shortages.

Hydro Power: top 5 countries

Hydro Power	Installed Capacity (MW)		Actual Generation (GWh)	
Country	2011	1993	2011	1993
China	231 000	44 600	714 000	138 700
Brazil	82 458	47 265	428 571	252 804
United States of America	77 500	74 418	268 000	267 326
Canada	75 104	61 959	348 110	315 750
Russian Federation	49 700	42 818	180 000	160 630
Rest of World	430 420	338 204	828 437	1 150 750
Global Total	**946 182**	**609 264**	**2 767 118**	**2 285 960**

Benefits	Drawbacks
Low operating costs	High CAPEX
No waste or CO_2 emissions	Significant land requirement for large plants with dams/lakes
Simple proven technology	Public resistance due to relocation or micro climate effects

Wind

Wind is available virtually everywhere on earth, although there are wide variations in wind strengths. The total resource is vast; estimated to be around a million GW 'for total land coverage'. If only 1% of this area was utilised, and allowance made for the lower load factors of wind plants (15–40%, compared with 75–90% for thermal plants) that would still correspond, roughly, to the total worldwide capacity of all electricity-generating plants in operation today.

World wind energy capacity has been doubling about every three and a half years since 1990. Total capacity at the end of 2011 was over 238GW and annual electricity generation around 377TWh, roughly equal to Australia's annual electricity consumption. China, with about 62GW, has the highest installed capacity while Denmark, with over 3GW, has the highest level per capita. Wind accounts for about 20% of Denmark's electricity production. It is difficult to compare today's numbers with those two decades ago, as measuring methodologies and tools are different.

As governments begin to cut their subsidies to renewable energy, the business environment becomes less attractive to potential investors. Lower subsidies and growing costs of material input will have a negative impact on the wind industry in recent years.

Wind power: top 5 countries

Wind	Installed Capacity (MW)		Actual Generation (GWh)	
Country	2011	1993	2011	1993
China	62 364	15	73 200	–
United States of America	46 919	1 814	120 177	3 042
Germany	29 071	650	48 883	–
Spain	21 673	52	41 790	117
India	15 880	40	19 475	45
Rest of World	62 142	–	74 087	–
Global Total	**238 049**	**–**	**377 613**	**–**

Benefits	Drawbacks
Simple technology, quick installation and dismantling of onshore installations	Intermittency
No fuel or waste costs	Grid integration challenges
Clean solution for remote areas	Reliance on subsidies

Solar PV

Solar energy is the most abundant energy resource and it is available for use in its direct (solar radiation) and indirect (wind, biomass, hydro, ocean etc.) forms. About 60% of the total energy emitted by the sun reaches the Earth's surface. Even if only 0.1% of this energy could be converted at an efficiency of 10%, it would be four times larger than the total world's electricity generating capacity of about 5 000GW. The statistics about solar PV installations are patchy and inconsistent. The table below presents the values for 2011 but comparable values for 1993 are not available.

The use of solar energy is growing strongly around the world, in part due to the rapidly declining solar panel manufacturing costs. For instance, between 2008–2011 PV capacity has increased in the USA from 1 168MW to 5 171MW, and in Germany from 5 877MW to 25 039MW. The anticipated changes in national and regional legislation regarding support for renewables is likely to moderate this growth.

League tables reserves: top 5 countries

Solar (PV)	Installed Capacity (MW)		Actual Generation (GWh)	
Country	**2011**	**1993**	**2011**	**1993**
Germany	25 039	–	19 340	–
Italy	12 773	–	10 730	–
United States of America	5 171	360	5 260	897
Japan	4 914	–	5 160	–
Spain	4 332	–	7 386	–
Rest of World	16 621	–	5 002	–
Global Total	**68 850**	**–**	**52 878**	**–**

Benefits	Drawbacks
High reliability, no moving parts	Intermittency
Quick installation and dismantling	Grid connection challenges
Suitable solution for remote areas	Use of toxic materials

Bioenergy and waste

Bioenergy is a broad category of energy fuels manufactured from a variety of feedstocks of biological origin and by numerous conversion technologies to generate heat, power, liquid biofuels and gaseous biofuels. The term "traditional biomass" mainly refers to fuelwood, charcoal, and agricultural residues used for household cooking, lighting and space-heating in developing countries. The industrial use of raw materials for production of pulp, paper, tobacco, pig iron so on, generates byproducts such as bark, wood chips, black liquor, agricultural residues, which can be converted to bioenergy.

The share of bioenergy in TPES has been estimated at about 10% in 1990. Between 1990 and 2010 bioenergy supply has increased from 38 to 52EJ as a result of growing energy demand. New policies to increase the share of renewable energy and indigenous energy resources are also driving demand. However, it is difficult to make accurate comparisons with earlier figures because of poor availability and low level of standardisation of data.

Benefits	Drawbacks
Domestic resource	Transportation and processing implications
Proven simple combustion technologies	Emissions of NOx and SOx
Biofuels as alternative for transport	Energy – Water/food aspects

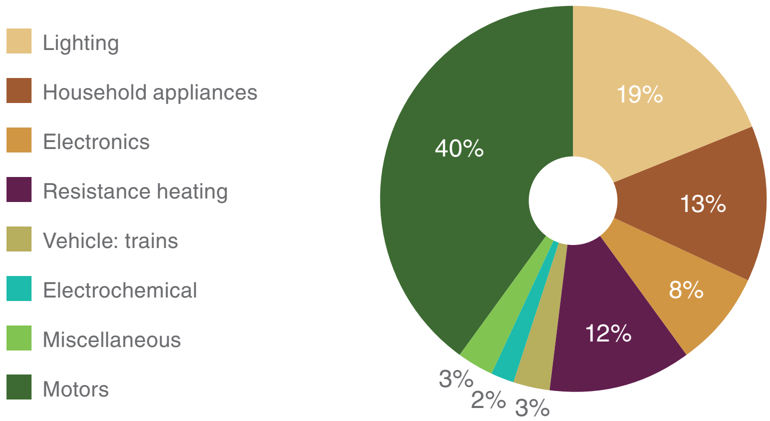
Energy efficiency

Energy efficiency is an important component of the energy economy. It is often called an "energy resource", because it helps to decrease the use of primary energy resources and achieve considerable savings. There is tremendous potential for energy efficiency improvements along the entire energy value chain. The 2013 WEC report, *World Energy Perspective: Energy Efficiency Technologies* provides some quantitative indicators for the various phases of the value chain and for specific industries. However, energy efficiency is not just a matter of using efficient technologies; the solutions should also take into account economic aspects. Energy efficiency technologies will be widely used only when economically viable, within their lifetime, and when there are no implementation barriers.

Examples of energy efficiency improvement potential for main technology groups:

- In Oil & Gas exploration the energy efficiency of the electric system, which today is 20%, could be increased up to 50%.
- In power generation the average efficiency of power plants is 34% for coal-fired installations compared with best available technology of 46% for coal and 61% for gas-fired units.
- In transmission and distribution electricity losses reach up to 12% and above.
- Buildings account for nearly 40% of the total energy consumption globally and it is estimated that potential energy savings in buildings could reach between 20 and 40%.

Global electricity demand by application



Three main sectors which account for approximately 70% of the total electricity consumption in the industrialised countries:

- motors (40–45%)
- lighting (15%)
- home appliances and consumer electronics (15%)

In some developing countries with large industries and outdated electrical equipment, the share of electricity consumed by motors is even higher. Globally electric motors consume about 9 000TWh/year, but more advanced models could save about 1 000TWh and reduce CO_2 emissions by 0.8Gt per year. This equals the total annual electricity consumption of a country like Japan.

Ambitious goals for energy efficiency are reaching beyond purely technical solutions to encompass cost-effectiveness, financing, acceptance, innovation and environmental impact assessment. The profitability of investing in energy efficiency technologies is often questioned. Unbiased comprehensive studies of energy efficiency solutions including cost/benefit assessments could help to promote understanding of the potential benefits. Energy efficiency requires a long-term commitment, and the financing framework should take this into account. The loan terms should cover the entire lifetime of the solution.

Cost of generation technologies

A recent joint WEC-BNEF (Bloomberg New Energy Finance) study demonstrates the levelised cost of electricity (LCOE) for a number of mainstream technologies. LCOE is the price that must be received per unit of output as payment for producing power in order to reach a specified financial return – or to put it simply, the price that project must earn per megawatt hour in order to break even. The LCOE calculation standardises the units of measuring the life cycle costs of producing electricity thereby facilitating the comparison of the cost of producing one megawatt hour for each technology. The simple formula for this calculation is shown below:

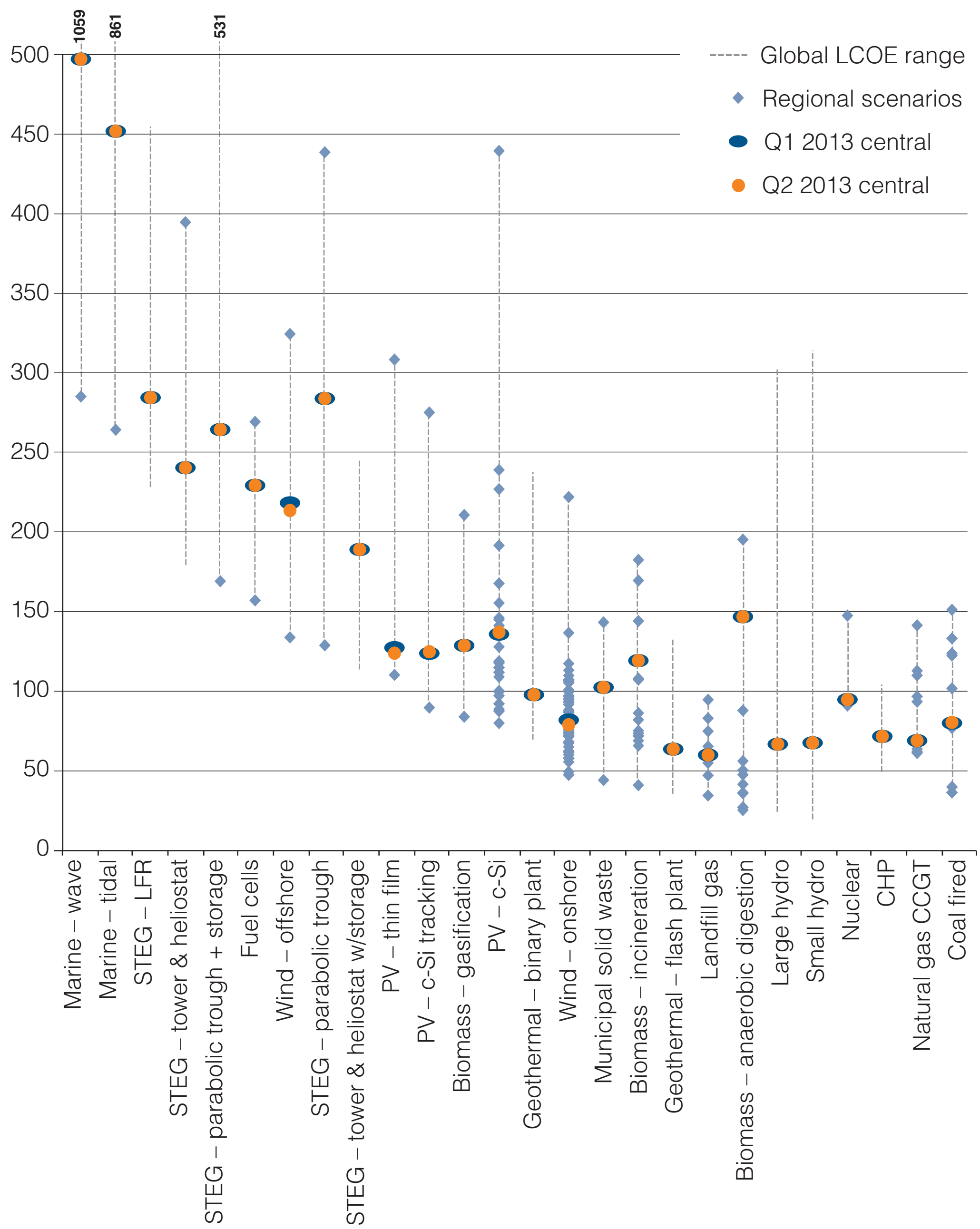
$$\text{LCOE} = \frac{\text{Annualised capex + fixed O\&M + variable O\&M + tax}}{\text{8 760 hours * resource factor * efficiency * availability}}$$

The LCOEs presented in the report reflect the actual costs of each technology and exclude all subsidies and support mechanisms. This makes it possible to compare the total costs of each technology on an equal basis, but does not represent the net costs faced by developers in the market and additional costs of volatility.

The figures used reflect the most recent data available for costs from Q1 and Q2 2013.

Global levelised cost of energy in Q2 2013 (USD/MWh)

Source: Bloomberg New Energy Finance.
Note: forecast is from BNEF New Normal forecast scenario from the BNEF Global Renewable Energy Market Outlook: http://about.bnef.com/presentations/global-renewable-energy-market-outlook-2013-fact-pack-2/



The road ahead

Demand for energy will continue to grow for decades to come. Population increases and a growing rate of electrification will place huge requirements on energy supplies. Global primary energy demand could increase by 50% by the middle of the century. At least 80% of this increase is expected to come from developing countries. The total primary energy demand of China alone is expected to double by 2035, and that of India to increase by almost 150% during the same period. Both countries with huge populations and high economic growth are expected to dominate the global consumption of energy resources in the coming years.

Key messages

The key messages emerging from the World Energy Resources survey 2013:

- The changes in the energy industry over the past 20 years have been significant. The growth in energy consumption has been higher than anticipated even in the high-growth scenarios. The energy industry has been able to meet this growth globally assisted by continuous increases in reserves' assessments and improving energy production and consumption technologies. The results of the 2013 WEC World Energy Resources survey show that there are more energy resources in the world today than 20 years ago, or ever before.

- It is obvious that moving away from fossil fuels will take years and decades, as coal, oil and gas will remain the main energy resources in many countries. Fuel-switching does not happen overnight. The leading world economies are powered by coal: about 40% of electricity in the United States and 79% of the electricity in China is generated in coal-fired thermal plants. These plants will continue to run for decades. The main issue for coal is the CO_2 penalty.

- Contrary to the expectations of the world running out of oil within a few decades, the so called notion of 'peak oil' which prevailed 20 years ago, has almost been forgotten. The global crude oil reserves are almost 60% larger today than in 1993 and the production of oil has gone up by 20%. If the unconventional oil resources such as oil shale, oil sands, extra heavy oil and natural bitumen are taken into account, the oil endowment of the world could be quadrupled. An increasing share of oil will be consumed in the rapidly growing transport sector, where it will remain the principal fuel.

- Natural gas is expected to continue its growth spurred by falling or stable prices, and thanks to the growing contribution of unconventional gas, such as shale gas. In addition to power generation, natural gas is expected to play an increasing role as a transport fuel.

- The future of nuclear energy is uncertain. While some countries, mainly in Europe, are making plans to withdraw from nuclear, other countries are looking to establish nuclear power generation.

- The development of renewables, excluding large hydro, has been considerably slower than expected 20 years ago. Despite the exponential growth of renewable resources in percentage terms, in particular wind power and solar PV, renewable energy still accounts for a small percentage of TPES in most countries. Their contribution to energy supply is not expected to change dramatically in the coming years. The continuing growth of renewables strongly depends on subsidies and other support provided by governments. Integration of intermittent renewables in the electricity grids also remains an issue, as it results in additional balancing costs for the system and thus higher electricity bills.

- Energy efficiency helps address the “energy trilemma” and provides an immediate opportunity to decrease energy intensity. This will achieve energy savings and reduce the environmental impacts of energy production and use.

Finally, demand for energy will continue to grow. Even if global energy resources seem to be abundant today, there are other constraints facing the energy sector, above all, significant capital investment in developing and developed economies is needed. The environment and climate, in particular, pose an additional challenge. Clean technologies will require adequate financing, and consumers all over the world should be prepared to pay higher prices for their energy than today. Energy is global and to make the right choices, decision makers should look at the global picture and base their decisions on a thorough life cycle analysis and reliable energy information. World Energy Council has been and remains the prime reference institution for energy resource assessments, independent of geopolitics.

Member Committees of the World Energy Council

Albania
Algeria
Argentina
Austria
Bahrain
Belgium
Bolivia
Botswana
Brazil
Bulgaria
Cameroon
Canada
Chad
China
Colombia
Congo (Democratic Republic)
Côte d'Ivoire
Croatia
Cyprus
Czech Republic
Denmark
Egypt (Arab Republic)
Estonia
Ethiopia
Finland
France
Gabon
Germany
Ghana
Greece
Hong Kong, China
Hungary
Iceland
India
Indonesia
Iran (Islamic Republic)
Ireland
Israel
Italy
Japan
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Kazakhstan
Kenya
Korea (Republic)
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Netherlands
New Zealand
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Nigeria
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Paraguay
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Qatar
Romania
Russian Federation
Saudi Arabia
Senegal
Serbia
Slovakia
Slovenia
South Africa
Spain
Sri Lanka
Swaziland
Sweden
Switzerland
Syria (Arab Republic)
Taiwan, China
Tanzania
Thailand
Trinidad & Tobago
Tunisia
Turkey
Ukraine
United Arab Emirates
United Kingdom
United States
Uruguay
Zimbabwe

1

Coal

Contents

Strategic insight

1. Introduction

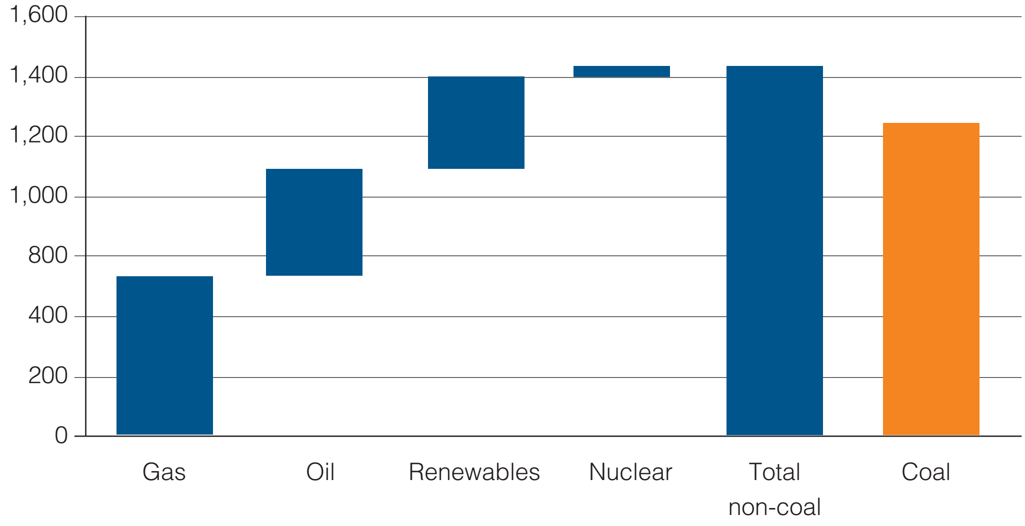
Coal in the global energy mix

Coal remains central to the global energy system. It is the world's largest source of electricity, accounting for around 40% of global electricity production. It is currently the world second largest source of primary energy, and is widely expected to replace oil as the world's largest source of primary within a few years. Coal's dominant position in the global energy mix is largely due to the fact it is abundant, widely distributed across the globe and affordable.

Wide distribution of coal is demonstrated in this report with major coal deposits existing on every continent. This report estimates there are 869 billion tonnes of coal reserves, which based on current production rates should last for around 115 years, significantly longer than conventional oil and gas reserves. Particularly important are the significant coal reserves in Asia and southern Africa, two regions of the world that face major challenges in providing energy to their populations

Unlike conventional oil and gas reserves, estimates of coal reserves can often be underestimated. Rather than a lack of coal resources, there is lack of incentive to prove up reserves. Exploration activity is typically carried out by mining companies with short planning horizons rather than state-funded geological surveys and there is no economic need for companies to prove long-term reserves. Coal resources are often estimated to be as much as 4-5 times

Figure 1.1
Incremental world primary energy demand by fuel, 2000-2010
Source: IEA, WEO 2011



greater than estimated reserves. This provides potential to increase coal reserves into the future. Furthermore reserve figures do not consider alternative ways of accessing energy from the coal resource, such as underground coal gasification.

China firmly holds the first place among coal producing countries. The United States remains the second largest coal producer, followed by India and Australia. Coal production increased significantly in Indonesia (15.8%), Colombia (12.7%), Ukraine (12.1%) and China (10.6%). Over three quarters of global coal consumption was accounted for by five countries: China, the United States, India, Russia and Japan. China alone accounted for over 48% of total global coal consumption. Coal consumption decreased by 2% on average across the OECD countries, however outside of the OECD, coal consumption increased by 8.6%, driven mainly by growing energy demand in China.

Despite projected declines in OECD countries, coal use is forecast to rise over 50% to 2030, with developing countries responsible for 97% of this increase, primarily to meet improved electrification rates.

Between 2000 and 2010 it is estimated that coal met around half of global incremental electricity demand (see figure below). Despite the rapid deployment of renewable energy technologies, particularly in the context of debates about climate change, it has been coal that has accounted for the largest increase in energy demand among the range of energy sources. The growth in coal usage, in both volume and percentage terms, was greater than any other fuel, including renewables. In fact, growth in coal consumption this century has almost equalled growth in oil plus gas plus nuclear plus renewables *combined*.

Coal has met this significant growth in energy demand because of its status as a reliable, widely distributed and affordable fuel, it is also the least subsidised of all fuel sources.

Coal's role in delivering energy access

As nations develop, they seek secure, reliable and affordable sources of energy to strengthen and build their economies – coal is a logical choice in many of these countries because it is widely available, safe, reliable and relatively low cost. One of the major challenges facing the world at present is that approximately 1.2 billion people live without any access to modern energy services. Approximately a further 1 billion have intermittent access to modern energy. Access to energy is a foundation stone of modern life and addressing the challenge of energy poverty is a major international priority and a key tool in eradicating extreme poverty across the globe.

Coal resources exist in many developing countries, including those with significant energy challenges. This report demonstrates that many countries with electricity challenges, particularly those in Asia and southern Africa, are able to access coal resources in an affordable and secure way to fuel the growth in their electricity supply. Coal will therefore play a major role in supporting the development of base-load electricity where it is most needed. Coal-fired electricity will be fed into national grids and it will bring energy access to millions and support economic growth in the developing world.

To demonstrate this fact, the International Energy Agency's World Energy Outlook 2011 highlights that "coal alone accounts for more than 50% of the total on-grid additions" required to achieve the its "Energy for All" case. This clearly demonstrates coal's fundamental role in supporting modern base-load electricity that is required to fuel economic development and alleviate poverty.

2. Technical and economic considerations

China, India and the developing world

The largest growing economies today are powered by coal and have significant coal reserves. The increase in coal consumption across the globe has predominantly been due to demand for greater electricity generation in China, India and other non-OECD countries which have seen total power generation double since 2000. Well over half of this new power generation has come from coal. China alone now uses as much coal as the rest of the world.

In 2012 it was announced that a key deliverable of the Millennium Development Goals – halving global poverty – had been achieved. However closer analysis shows that virtually all of the world's poverty reduction between 1981 and 2008 took place in China, 80% fuelled by coal.

World Bank estimates show that the percentage of those living below USD1.25 a day in China decreased from 84% to 13% between 1981 and 2008. During this time China lifted 662 million people out of poverty. Coal played a key role in achieving such a significant reduction in poverty in China. During the period 1980-2008 Chinese annual coal consumption increased by more than 400% from 626 million tonnes to 2.7 billion tonnes.

Electrification is a vital component of China's poverty alleviation campaign which has built up basic infrastructure and created local enterprises throughout China. As a result, from 1985 to 2003, electricity production in China rose by over 1500 TWh, of which around 80% is coal-fired.

It is clear that this development pathway is set to be repeated in other parts of developing Asia.

In India the increasing use of coal reflects significant growth in the economy which in turn increases demand for electricity as well as materials in which coal is a key component of production such as steel and cement. It is estimated that around 295 million people today still live in energy poverty in India. Although other energy sources will play a role, India's domestic coal reserves, relatively easy access to affordable imported coal and its ability to meet the sheer scale of demand mean that much of the future energy demand in India will be met by coal. The Indian Government anticipates an additional 60GW of coal-fired power generation to be built in the country by 2017 which would increase total coal-fired capacity to approximately 175GW.

A similar story will be told in elsewhere in South Asia, and southern Africa also provides another example. In South Africa coal is being used to bring electricity to some of the 12.5 million people – 25% of the South African population – who lack it. This electricity will help address the fact that half of South Africa's population lives in poverty. International support for the construction of modern, highly efficient coal-fired power plants in South Africa demonstrates the importance of coal in meeting the demand for reliable base-load electricity to help deliver economic development.

Cleaner energy from coal

With the ever-increasing demand for coal, particularly in the developing world, the use of low emission coal technologies becomes increasingly important if international targets on climate change are to be achieved. The two principal avenues for reducing carbon emissions from coal-fired power generation are through use of high efficiency, low emission power plants and carbon capture, use and storage.

High-efficiency, low-emission power generation

Efficiency in coal-fired power generation will play an important role in the future production of electricity. This is particularly the case with the potential of higher efficiency power generation to reduce CO_2 emissions.

Improving efficiency levels increases the amount of energy that can be extracted from a single unit of coal. Increases in the efficiency of electricity generation are essential in tackling climate change. A one percentage point improvement in the efficiency of a conventional pulverised coal combustion plant results in a 2-3% reduction in CO_2 emissions. Highly efficient modern supercritical and ultra-supercritical coal plants emit almost 40% less CO_2 than subcritical plants.

In 2011 roughly 50% of all new coal-fired power plants used HELE technologies, predominantly supercritical and ultra-supercritical coal combustion units. However, about three quarters of all operating units today use non-HELE technology.

Efficiency improvements include the most cost-effective and shortest lead time actions for reducing emissions from coal-fired electricity. This is particularly the case in developing and transition countries where existing plant efficiencies are generally lower and coal use in electricity generation is increasing.

Although the deployment of new, highly efficient plants is subject to local constraints, such as ambient environmental conditions and coal quality, deploying the most efficient plant possible is critical to enable these plants to be retrofitted with CCS in the future.

Efficient plants are a prerequisite for retrofitting with CCS – as capturing, transporting and storing the plant's CO_2 consumes significant quantities of energy. Highly inefficient plants will undermine capacity to deploy CCS technologies.

Improving the efficiency of the oldest and most inefficient coal-fired plants would reduce CO_2 emissions from coal use by almost 25% representing a 6% reduction in global CO_2 emissions. (By way of comparison, under the Kyoto Protocol, Parties have committed to reduce their emissions by "at least 5%".) These significant emissions reductions can be achieved by the replacement of plants that are < 300 MW capacity and older than 25 years, with larger and significantly more efficient plants and, where technically and economically appropriate, the replacement or repowering of larger inefficient plants with high-efficiency plants of >40%.

Carbon capture, use and storage

Carbon capture and storage technology will be a key technology to reduce CO_2 emissions, not only from coal, but also natural gas and industrial sources. Figures in the IEA's World Energy Outlook 2011 report estimate the potential for CCS to contribute 22% of global CO_2 mitigation through to 2035. Further analysis by the IEA in their Energy Technology Perspectives 2010 report also shows that climate change action will cost an additional USD4.7 trillion without CCS.

Like all new low emission energy technologies however, CCS will cost significantly more than conventional technology and requires extended development time. While available on a component-by-component basis, CCS has not yet been commercially proven on an integrated basis or at the scale required to meet global greenhouse gas concentration targets.

Once demonstrated, CCS will enable countries to rely on secure and affordable energy sources such as coal without compromising their environmental ambitions.

Key to operationalizing CCS however is establishing a sustainable business case and this is most likely to be met in the near term at least through the utilization of captured CO_2 and particularly through Enhanced Oil Recovery (EOR). CCUS and EOR can provide a pathway to two important energy goals of many countries – producing reliable and affordable electricity from coal power plants while reducing greenhouse gas emissions and producing more oil to meet growing demand and enhance national energy security. Utilising the CO_2 from the consumption of fossil fuels is a crucial step in economically reducing greenhouse gas emissions.

In its 2013 report, "Tracking Clean Energy Progress", the International Energy Agency notes that patent applications that relate to CCS have increased by 45% since 2006, signalling commercial interest in the technology. However, the Agency estimates that around 75% of investments in CCS projects since 2007 have come from private financing and calls for greater public funding in this area.

Global trade in coal

Coal is a global industry, with coal found in over 70 countries and actively mined in 50 countries. Coal is readily available from a wide variety of sources in a well-supplied worldwide market. Coal can be transported to demand centres quickly, safely and easily by ship and rail. A large number of suppliers are active in the international coal market, ensuring a competitive and efficient market.

Coal is traded all over the world, with coal shipped huge distances by sea to reach markets Over the last twenty years:

- seaborne trade in steam coal has increased on average by about 7% each year
- seaborne coking coal trade has increased by 1.6% a year.

Overall international trade in coal reached 1142Mt in 2011; while this is a significant amount of coal it still only accounts for about 15% of total coal consumed. Most coal is used in the country in which it is produced.

Transportation costs account for a large share of the total delivered price of coal, therefore international trade in steam coal is effectively divided into two regional markets:

- the Atlantic market, made up of importing countries in Western Europe, notably the UK, Germany and Spain.
- the Pacific market, which consists of developing and OECD Asian importers, notably Japan, Korea and Chinese Taipei. The Pacific market currently accounts for about 57% of world seaborne steam coal trade.

Indonesia has overtaken Australia as the world's largest coal exporter. It exported over 300Mt of coal in 2011.

Australia remains the world's largest supplier of coking coal, accounting for roughly 50% of world exports.

Emerging coal technologies

In addition to improvements in the efficiency of coal-fired power stations and the deployment of CCS for electricity generation, the world's significant coal resources can also be deployed to support other energy needs.

Coal to liquids

Converting coal to a liquid fuel (CTL) – a process referred to as coal liquefaction – allows coal to be utilised as an alternative to oil.

South Africa has been producing coal-derived fuels since 1955. Not only are CTL fuels used in cars and other vehicles, but South African energy company Sasol's CTL fuels also have approval to be used in commercial jets. Currently around 30% of the country's gasoline and diesel needs are produced from indigenous coal. The total capacity of the South African CTL operations now stands in excess of 160,000bbl/d.

CTL is particularly suited to countries that rely heavily on oil imports and have large domestic reserves of coal.

Fuels produced from coal can also be used outside the transportation sector. In many developing countries, health impacts and local air quality concerns have driven calls for the use of clean cooking fuels. Replacing traditional biomass or solid fuels with liquefied petroleum gas (LPG) has been the focus of international aid programmes. LPG however, is an oil derivative – and is thus affected by the expense and price volatility of crude oil. Coal-derived dimethyl ether (DME) is receiving particular attention today as it is a product that holds out great promise as a domestic fuel. DME is non-carcinogenic and non-toxic to handle and generates less carbon monoxide and hydrocarbon air pollution than LPG.

Underground coal gasification

Underground coal gasification (UCG) is a method of converting unworked coal - coal still in the ground - into a combustible gas which can be used for industrial heating, power generation or the manufacture of hydrogen, synthetic natural gas or diesel fuel.

In the last few years there has been significant renewed interest in UCG as the technology has moved forward considerably. China has about 30 projects using underground coal gasification in different phases of preparation. India plans to use underground gasification to access an estimated 350 billion tonnes of coal.

South African companies Sasol and Eskom both have UCG pilot facilities that have been operating for some time, giving valuable information and data. In Australia, Linc Energy has the Chinchilla site, which first started operating in 2000. Demonstration projects and studies are also currently under way in a number of countries, including the USA, Western and Eastern Europe, Japan, Indonesia, Vietnam, India, Australia and China, with work being carried out by both industry and research establishments.

3. Market trends and outlook

The road ahead

In its recent report *Time to get real – the case for sustainable energy policy*, the World Energy Council posed the energy trilemma of energy security, social equity and environmental impact mitigation. From the coal industry's perspective the trilemma is perhaps better described through the prisms of (1) energy access in the developing world, (2) energy security and affordability in the developed world and (3) environmental protection globally as being the main challenges that need to be addressed. These challenges can be addressed as integrated priorities.

As this report highlights the world benefits from abundant reserves of coal, much of it in regions that still have much work to do to improve access to energy and thereby help improve living standards. All energy sources will have a role to play in meeting this challenge however many countries will be looking to utilise their own natural resources to achieve that goal and affordable, reliable and accessible coal will be a key part of that development strategy.

Coal's wide availability in the developed world also proves to be a vital component in ensuring affordable fuel can contribute to limiting rising electricity prices, often brought about by poor economic decisions driven purely by environmental objectives.

An effective and sustainable response to the challenge of climate change must integrate environmental imperatives with the legitimate aims of energy security and economic development, including poverty alleviation.

Ensuring secure, affordable and sustainable energy requires a diverse energy mix. As this report shows, coal is a major economic and energy resource and will remain a key part of the energy mix well into the future.

Benjamin Sporton
World Coal Association

Reserves and production

1. Global tables

Table 1.1

Coal: proved recoverable reserves at end-2011 (million tonnes)

Sources: WEC Member Committees, 2011; data reported for previous WEC reports of Energy Resources; national and international published sources

	Bituminous including anthracite	Sub-bituminous	Lignite	Total
Afghanistan	66			66
Albania			794	794
Algeria	59			59
Argentina		550		550
Armenia	163			163
Australia	37 100	2 100	37 200	76 400
Austria			333	333
Bangladesh	293			293
Belarus			100	100
Bolivia	1			1
Bosnia-Herzegovina	484		2 369	2 853
Botswana	40			40
Brazil		6 630		6 630
Bulgaria	2	190	2 174	2 366
Canada	3 474	872	2 236	6 582
Central African Republic			3	3
Chile		155		155
China	62 200	33 700	18 600	114 500
Colombia	6 746			6 746
Congo (Democratic Rep.)	88			88
Croatia	4			4
Czech Republic	181		871	1 052
Ecuador			24	24
Egypt (Arab Rep.)	16			16
Georgia	201			201
Germany	48		40 500	40 548
Greece			3 020	3 020
Greenland		183		183
Hungary	13	439	1 208	1 660
India	56 100		4 500	60 600
Indonesia		28 017		28 017
Iran (Islamic Rep.)	1 122			1 122
Ireland	14			14
Italy		50		50
Japan	337		10	347
Kazakhstan	21 500		12 100	33 600
Korea (Democratic People's Rep.)	300	300		600

Korea (Republic)	–	126		126
Kyrgyzstan			812	812
Laos	4		499	503
Macedonia (Republic)			332	332
Malawi		2		2
Malaysia	4			4
Mexico	860	300	51	1 211
Mongolia	1 170		1 350	2 520
Montenegro	142			142
Morocco	82		40	122
Mozambique	212			212
Myanmar (Burma)	2			2
Nepal		1		1
New Caledonia	2			2
New Zealand	33	205	333	571
Niger	70			70
Nigeria	21	169		190
Norway		5		5
Pakistan		166	1 904	2 070
Peru	44			44
Philippines	41	170	105	316
Poland	4 178		1 287	5 465
Portugal	3		33	36
Romania	10	1	280	290
Russian Federation	49 088	97 472	10 450	157 010
Serbia	1	10	13 400	13 411
Slovakia	2		260	262
Slovenia		24	199	223
South Africa	30 156			30 156
Spain	200	300	30	530
Suriname	12			12
Swaziland	144			144
Taiwan, China	1			1
Tajikistan	375			375
Tanzania	200			200
Thailand			1 239	1 239
Turkey	322		8 380	8 702
Ukraine	15 351	16 577	1 945	33 873
United Kingdom	228			228
United States of America	108 501	98 618	30 176	237 295
Uzbekistan	47		1 853	1 900
Venezuela	479			479
Vietnam	150			150
Zambia	10			10
Zimbabwe	502			502
TOTAL WORLD	**403 197**	**287 333**	**201 000**	**891 530**

Table 1.2
Coal: 2011 production (million tonnes)

Sources: WEC Member Committees, 2011; data reported for previous WEC reports of Energy Resources; national and international published sources

	Bituminous	Sub-bituminous	Lignite	Total	R/P
Albania	0.1			0.1	> 100
Argentina		0.3		0.3	> 100
Australia	295.6	36.5	65.5	397.6	> 100
Bangladesh	0.6			0.6	> 100
Bosnia-Herzogovina			11.2	11.2	> 100
Botswana	0.9			0.9	7
Brazil		5.5		5.5	> 100
Bulgaria	0.0	2.7	34.5	37.2	64
Canada	34.6	22.8	9.7	67.1	98
Chile	0.2		0.3	0.5	> 100
China	3 236.8		146.9	3 383.7	34
Colombia	85.8	0.0		85.8	79
Congo (Democratic Rep.)	0.1			0.1	> 100
Czech Republic	11.3		46.6	57.9	18
Georgia	0.4			0.4	> 100
Germany	12.9		176.5	189.5	> 100
Greece			65.7	65.7	46
Hungary			9.4	9.4	> 100
India	483.7		32.1	515.8	> 100
Indonesia		353.3		353.3	79
Iran (Islamic Rep.)	2.3			2.3	> 100
Italy		0.1		0.1	> 100
Japan	1.3			1.3	> 100
Kazakhstan	116.3		8.4	124.7	> 100
Korea (Democratic People's Rep.)	26.0	7.4		33.4	18
Korea (Republic)		2.8		2.8	45
Kyrgyzstan	0.1		0.3	0.4	> 100
Laos	0.6			0.6	> 100
Macedonia (Republic)			7.3	7.3	45
Malawi		0.1		0.1	20
Malaysia		1.2		1.2	3
Mexico	2.0	13.7		15.7	77
Mongolia	0.2		9.6	9.8	> 100
Montenegro			1.7	1.7	84
Myanmar (Burma)			0.3	0.3	7
New Zealand	2.5	2.2	0.2	4.9	> 100
Niger	0.2			0.2	> 100
Norway		3.4		3.4	1
Pakistan	0.5	2.5	0.9	3.9	> 100
Peru	0.1			0.1	> 100
Philippines		3.6		3.6	88
Poland	67.6		62.9	130.5	42
Romania	2.8	0.6	31.8	35.2	8
Russian Federation	246.0		80.5	326.5	> 100
Serbia	0.0	0.7	40.0	40.7	> 100
Slovakia	3.9			4.0	66
Slovenia		0.5	4.0	4.5	50

South Africa	251.0			251.0	> 100
Spain	7.3	2.9		10.2	52
Swaziland	0.2			0.2	> 100
Tajikistan	0.2	N		0.2	> 100
Thailand			18.0	18.0	69
Turkey	2.6		74.3	76.9	> 100
Ukraine	59.5		0.2	59.7	> 100
United Kingdom	18.1			18.1	13
United States of America	500.5	510.5	81.0	1 092.0	> 100
Uzbekistan	0.1		3.0	3.1	> 100
Venezuela	6.4			6.4	75
Vietnam	39.8			39.8	4
Zambia	0.2			0.2	50
Zimbabwe	2.7			2.7	> 100
TOTAL WORLD	**5 525.1**	**974.0**	**1 023.0**	**7 520.1**	**> 100**

2. Regional tables

Table 1.3
Coal Regional Summary tables

Summary tables show top five countries per region only, ranked by reserves.

Country	Region	Coal Reserves Million tonnes	Production Million tonnes	R/P years
South Africa	Africa	30156	251	> 100
Zimbabwe	Africa	502	2.7	> 100
Mozambique	Africa	212		
Tanzania	Africa	200		
Nigeria	Africa	190		
Rest of region		357	2	0
Africa total		31617	255.4	
China	East Asia	114500	3 383.7	34
Korea (DRC)	East Asia	600	33.4	18
Japan	East Asia	347	1.3	> 100
Korea (Republic)	East Asia	126	2.8	45
Taiwan	East Asia	1		
Rest of region		0	0	
East Asia total		115574	3421	
Russian Federation	Europe	157010	326.5	> 100
Germany	Europe	40548	189.462	> 100
Ukraine	Europe	33873	59.7	> 100
Serbia	Europe	13411	40.687	> 100
Turkey	Europe	8702	76.9	> 100
Rest of region		20143	397	
Europe total		273 687.0	1 090.1	
Colombia	Latin America & The Caribbean	6746	85.5	79
Brazil	Latin America & The Caribbean	6630	5.505	> 100
Argentina	Latin America & The Caribbean	550	0.245	> 100
Venezuela	Latin America & The Caribbean	479	6.4	75
Chile	Latin America & The Caribbean	155	0.5	> 100
Rest of region		69	0	
LAC total		14629	99	

Iran	Middle East & North Africa	1122	2.3	> 100
Morocco	Middle East & North Africa	122		
Algeria	Middle East & North Africa	59		
Egypt	Africa	16		
Rest of region		0	0	
MENA total		1319	2	
Mexico	North America	1211	15.7	77
Canada	North America	6582	67.1	98
United States of America	North America	237 295.0	1 092.0	> 100
Rest of region		0.0	0.0	
North America total		245 088.0	1 174.8	
India	South & Central Asia	60600	515.8	> 100
Kazakhstan	South & Central Asia	33600	124.7	> 100
Mongolia	South & Central Asia	2520	9.8	> 100
Pakistan	South & Central Asia	2070	3.9	> 100
Uzbekistan	South & Central Asia	1900	3.1	> 100
Rest of region		1710	1	
South & Central Asia total		102 400.0	658.5	
Australia	Southeast Asia & Pacific	76400	397.6	> 100
Indonesia	Southeast Asia & Pacific	28017	353.3	79
Thailand	Southeast Asia & Pacific	1239	18.0	69
New Zealand	Southeast Asia & Pacific	571	4.9	> 100
Laos	Southeast Asia & Pacific	503	0.6	> 100
Rest of region		486	45	
Southeast Asia & Pacific		107216	819	
Total World		**891530**	**7520.103**	**> 100**

Country notes

The following Country Notes on Coal provide a brief account of countries with significant peat 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.

Argentina

Proved amount in place (total coal, million tonnes)	8 102
Proved recoverable reserves (total coal, million tonnes)	550
Production (total coal, million tonnes)	0.3

The Argentinian WEC Member Committee has reported proved amounts in place of 752 million tonnes of sub-bituminous coal and 7 350 million tonnes of lignite, which are found in two main deposits, Río Coyle with some 5 billion tonnes in place, and the middle course of the Río Santa Cruz, with 2.35 billion. Both these deposits lie in the Río Leona formation. The only proved reserves reported are 550 million tonnes of sub-bituminous. Undiscovered coal of this rank estimated to be in place amounts to 300 million tonnes, of which 100 million is regarded as recoverable.

Coal output from the Río Turbio mine is currently about 300 thousand tonnes per annum, and is used for electricity generation. A 240 MW coal-fired mine-mouth power plant, currently under construction, is scheduled to enter service in mid-2011. According to the Argentinian Member Committee, this development will require a quadrupling of Rio Turbio's output.

Australia

Proved amount in place (total coal, million tonnes)	100 500
Proved recoverable reserves (total coal, million tonnes)	76 400
Production (total coal, million tonnes)	397.6

Australia is endowed with very substantial coal resources. Total production of raw black coal in Australia in financial year 2010-11 was 397 million tonnes (Mt.), down from 471 Mt. in 2009-10. This drop was largely as a result of the Queensland floods of January 2011 where production in that State fell by some 30% (see below).

After processing, 326 Mt. of black coal was available for both domestic use and for export in 2010-11. Again, this represented a drop in production of some 14% from the 366 Mt. produced in 2009-10.

New South Wales and Queensland remained the main producing states with around 97% of Australia's saleable output of black coal, and almost all of Australia's black coal exports.

Australia has USD26.5 billion in advanced coal mining projects and associated infrastructure, involving more than 74 million additional tonnes of coal production by 2014. 'Less advanced' coal mine and coal infrastructure projects have a potential capital expenditure of USD46.6 billion, if all projects were to proceed.

A little over half of the recoverable bituminous, and all of the recoverable lignite, have been reported to be 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 119 billion tonnes, of which 75 billion tonnes is estimated to be recoverable. Comparable figures for brown coal are 174 billion tonnes and 156 billion tonnes, respectively.

Brazil

Proved amount in place (total coal, million tonnes)	6 640
Proved recoverable reserves (total coal, million tonnes) (see remarks below)	6 630
Production (total coal, million tonnes)	5.5

Brazil has considerable reserves of sub-bituminous coal, which are mostly located in the southern states of Rio Grande do Sul, Santa Catarina and Paraná.

The Brazilian WEC Member Committee has reported that the remaining proved amount of sub-bituminous coal in place was 6 640 million tonnes. The same source assesses Brazil's proved recoverable reserves to be 6 630 million tonnes. This is higher than in the last report.

The maximum depth of the deposits is 870 m, whilst the minimum seam thickness is 0.5 m. It is estimated that 21% of the stated level of proved recoverable reserves could be exploited through surface mining.

The Member Committee quotes additional discovered amounts of coal in place at lower levels of confidence as approximately 10.8 billion tonnes classified as 'probable' and more than 6.5 billion tonnes as 'possible'. It also estimates that a further amount of around 8.3 billion tonnes of coal is recoverable from undiscovered resources.

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.

In Brazil, coal's share in the energy mix is about 5% and only 1.3% in the electricity generation. The main uses of coal are in the steel industry and for power generation. Brazilian coal is considered to be low quality, with high ash content and low carbon content, which makes its use outside the coal deposit regions unviable. As such, more than 98% of coal is imported.

In 2010 Brazil consumed around 20 million tonnes of coal, of which 14.2 million tonnes was imported. Of this 20 million tonnes, 4.4 million tonnes (22%) was used in electricity generation and the remainder was used in industry.

Canada

Proved amount in place (total coal, million tonnes)	22 022
Proved recoverable reserves (total coal, million tonnes)	6 582
Production (total coal, million tonnes)	67

Coal is by far Canada's most abundant fossil fuel, with 6.6 billion tonnes of recoverable coal reserves. Canada has anthracite, bituminous, sub-bituminous, lignite coal deposits. More than 90% of Canada's coal deposits are located in western provinces which provide a strategic advantage because of the close proximity of west coast ports.

Canadian coal production has been around 60 million tonnes over the last decade however in 2012 coal production increased to 67 million tonnes. 38 million tonnes (56%) was thermal coal produced mainly in the prairies and 29 million tonnes was metallurgical (steel-making) coal, produced in Western Alberta and B.C.

To meet its rapid infrastructure growth and consumer demand for things such as vehicles and home appliances, Asia has turned to Canada for its high-quality steel-making coal. As Canada's largest coal trading partner, coal exports to Asia accounted for 73% of total exports in 2010.

40% of the coal produced in Canada is exported. In 2010, exports totalled 33 million tonnes, a 22% increase from the previous year. The majority of the coal exported was steel-making coal.

The Canadian WEC Member Committee has reported the following estimates of recoverable reserves (in millions of tonnes), as provided by Natural Resources Canada: bituminous coals (including anthracite) 3 474; sub-bituminous grades 872; and lignite 2 236. The corresponding amounts of coal remaining in place from which these tonnages could be extracted are (respectively) 4 651, 3 430 and 13 941 million tonnes.

Estimates of the remaining tonnages of coal in place that are considered to be additional to the 'proved' or 'measured' amounts of each rank total more than 300 billion tonnes. Within this enormous in situ figure, remaining discovered resources add up to 176.5 billion tonnes, of which 'probable/indicated' resources total 50.6 billion tonnes and 'possible/inferred' 125.9 billion. Undiscovered resources ('hypothetical/speculative') are estimated to add another 126 billion. While these figures are necessarily highly approximate, they do serve to underline Canada's massive coal endowment.

Around 88% of Canadian coal consumption is used for electricity generation, 7% in the steel industry and 5% 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 amount in place (total coal, million tonnes)	NA
Proved recoverable reserves (total coal, million tonnes) (see remarks below)	114 500
Production (total coal, million tonnes)	3 384

Coal still is The King in China with vast reserves located within economic reach of the energy consumer. The recent announcements about Chinese coal consumption indicate that China alone accounts for more than 50% of the global total annual coal consumption. China is a major force in world coal, standing in the front rank in terms of reserves, production and consumption. In the continued absence of reliable published information regarding China's coal resources and reserves, compounded by problems of definition and terminology, there has been a considerable amount of controversy over the best level to quote for proved recoverable reserves. Not infrequently, commentators appear to confuse in-place amounts with recoverable tonnages.

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, implying a reserves-to-production ratio of 38.

The same figure for total proved reserves (114.5 billion tonnes) 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, indicated a degree of continuity in the official assessments of China's coal reserves and supported the retention of the level originally advised by the Chinese WEC Member Committee in 1991.

Further confirmation that the level of proved reserves used in the present and previous Surveys is of the right order is provided by the Chinese Statistical Yearbook, published by the National Bureau of Statistics. Since 2002, this publication has specified China's 'ensured reserves' of coal which, according to the Ministry of Land and Natural Resources, have an average recovery ratio of 35%. Applying this rate to the 'ensured reserves' quoted for 2008 in the Yearbook (326.1 billion tonnes) produces 114.1 billion tonnes, a figure almost identical to the level of proved recoverable reserves adopted for this Survey.

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.

Colombia

Proved amount in place (total coal, million tonnes)	NA
Proved recoverable reserves (total coal, million tonnes)	6 508
Production (total coal, million tonnes)	85.8

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 (Ingeominas), 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 report, the WEC Member Committee for Colombia has reported proved recoverable reserves of 6 508 million tonnes based on the Ingeominas end-2003 measured reserves, adjusted for cumulative coal production in 2004-2011, inclusive. ‘Indicated reserves’ quoted by Ingeominas in the afore-mentioned publication were 4 572 million tonnes, whilst ‘inferred’ tonnages were 4 237 million and ‘hypothetical’ resources 1 120 million. The ‘indicated’ and ‘inferred’ levels are reported by the Member Committee under the headings of ‘probable’ and ‘possible’, respectively.

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 bituminous in Table 1.1. The measured reserves of Alto San Jorge were 381 million tonnes at end-2003 and annual output is approximately 350 000 tonnes, implying end-2008 reserves of about 380 million tonnes.

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.

Exports account for more than 90% of Colombia’s coal production; Cerrejón North remains one of the world’s largest export mines.

Colombia is the world’s tenth largest producer of hard coals and the fourth largest exporter of coal, based on 2009 data. The U.S. Geological Survey states that Colombia is the largest coal producer in South America and has the largest reserves in the region. It also states that coal mining for export is booming in Colombia, with production having increased by 80% since 1999.

The majority of Colombia’s coal exports are shipped to European markets due to shorter distances and lower freight costs compared to the rapidly growing Asian markets. Colombia is considered to be a low-cost producer with its coal highly sought after due to its low sulphur content.

In Colombia, the state owns all hydrocarbon reserves and private companies operate coal mines under concession contracts with the state.

Czech Republic

Proved amount in place (total coal, million tonnes)	4 336
Proved recoverable reserves (total coal, million tonnes)	1 052
Production (total coal, million tonnes)	57.9

The Czech Republic WEC Member Committee has reported coal resources and reserves provided by the Czech Geological Survey (Geofond). The remaining discovered amount in place (in Czech terminology, ‘economic explored reserves’) are quoted as 1 519 million tonnes of bituminous coal and 2 362 million tonnes of brown coal/lignite, of which respectively 181 and 871 million tonnes are classed as recoverable (‘exploitable’) reserves.

In addition to the proved amounts, the Member Committee reports substantial quantities of probable ('economic prospected') and possible ('potentially economic') reserves: in millions of tonnes, these are quoted as respectively 5 999 and 8 821 for bituminous and 2 663 and 4 523 for brown coal/lignite. Total known resources remaining in place are thus some 16.3 billion tonnes of bituminous and 8.9 billion tonnes of brown coal/lignite.

The maximum depth of deposits varies from 1 600 m in the case of bituminous to 500 m for brown coal/lignite; minimum seam thicknesses range from 0.6 (for bituminous) to 1.5 for brown coal/lignite.

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.

The Czech WEC Member Committee points out that Czech coal statistics now show brown coal (previously classed as sub-bituminous coal) with lignite.

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 brown coal/lignite, which is still the main power station fuel.

The Czech Republic is heavily dependent on coal for its energy needs and relies mostly on extensive reserves of brown coal or lignite in north Bohemia, in the northwest of the country, and of hard coal in the east of the country, where the Upper Silesian Basin falls within Czech territory. Between 1993 and 2003 coal consumption decreased by 26 per cent, mainly due to the commissioning of two new units at the Temelin nuclear power station. In 2004, in line with EU regulations, the Czech government lifted quotas on coal imported from Poland and Ukraine.

The Czech Republic's coal industry consists of six companies: three hard coal (black) mining companies (Ostrasko-Karvinske Doly; Ceskomoravske Doly; and Zapadoceske Uhelne Doly); and three lignite (brown) mining companies (Mostecká uhelná spolecnost, Severoceske Doly, and Sokolovska uhelna).

According to the State Energy Policy, coal will remain the country's primary energy source in the future in spite of the increased use of nuclear energy and natural gas. The government expects coal to account for 30.5 percent of consumption in 2030.

Germany

Proved amount in place (total coal, million tonnes)	NA
Proved recoverable reserves (total coal, million tonnes)	40 548
Production (total coal, million tonnes)	189.5

The German WEC Member Committee has reported coal reserves on the basis of data provided by the German Federal Institute for Geosciences and Natural Resources (BGR).

Proved recoverable reserves are given as 40 548 million tonnes, almost all 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 2018, when subsidised hard coal mining is due to be phased out. 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.

In previous reports only the proved recoverable amount of lignite reserves in existing and planned surface mines was reported. For better comparability with reserve data from other countries the present numbers report the entire German lignite reserves.

BGR's category 'resources' (using its own definition, which differs from WEC usage) amounts to around 82.9 billion tonnes of hard coal and 36.5 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.

Over three-quarters of German hard coal production is derived from the Ruhr Basin (Ruhr and Ibbenbüren mining districts). The coal qualities range from anthracite to high-volatile, strongly-caking bituminous coal. The second largest German coalfield is situated in the Saar Basin, 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 Rhineland region is the largest single formation in Europe in terms of lignite production. In the former East Germany there are major deposits of lignite in the Central-German (at Halle/Leipzig) and Lusatian mining districts, which have considerable domestic importance. Germany is still the world's largest lignite producer.

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 t/y) is converted into lignite products such as briquettes, dust, coal for fluidised circulating beds and coke for the industrial, residential and commercial markets.

Germany has considerable reserves of hard coal (48 million tonnes) and lignite (40,500 million tonnes), making these the country's most important indigenous source of energy.

Germany's primary energy consumption amounted to 480 Mtce in 2010. Oil accounted for the largest share (33.6%), followed by coal (22.8 %), natural gas (21.8 %) and nuclear energy (10.9 %). Renewable energy reached 9.5 %.Within coal, hard coal accounted for 12.1 % and lignite for 10.7 % of primary energy consumption. Germany is dependent on energy imports to a large extent, except in the case of lignite. About 77% of hard coal was imported, in comparison with 98% of oil and 87% of gas. The power generation structure is characterised by a widely diversified energy mix. In 2010, gross power output was as follows: 42.4% from coal (of which 23.7% was from lignite and 18.7 % from hard coal), 22.6 % from nuclear, 13.6 % from natural gas, 16.5 % from renewable energy sources and 4.9% from other sources. This means that hard coal and lignite, as well as nuclear energy, are the mainstays of the German power industry.

Greece

Proved amount in place (total coal, million tonnes)	5 800
Proved recoverable reserves (total coal, million tonnes)	3 020
Production (total coal, million tonnes)	65.7

Coal resources are all in the form of lignite. According to the Ministry of Development's Energy Outlook of Greece total 'remaining exploitable deposits' of lignite in 2008 were 3 020 million tonnes. 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 the lignite-mining areas, there are 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 6th largest in the world. Greece has no hard coal reserves, and consequently imports hard coal from South Africa, Russia, Venezuela, and Colombia.

Greece is second only to Germany in the EU for lignite coal production. Greece had 2011 coal production of 57.5 million tonnes, 0.18% of the world total. Domestic production has been partly opened to private companies, but the Public Power Corporation (PPC) remains the largest producer with the right to exploit 63% of known reserves.

Coal is Greece's single most important local energy source. Lignite and low quality black coal is used to generate power. Greece had 2011 coal consumption of 7.32 million tonnes oil equivalent, a change of -0.4% on 2010 and equivalent to 0.19% of the world total.

The Public Power Corporation (PPC) is Greece's main electricity provider, producing 95 % of Greece's total electricity supply. Lignite - fired generation accounts for 70% of total output. Exclusive rights for production of electricity from lignite are granted to the PPC, now a public company traded on the Athens and London stock exchanges, but in which the Greek Government retains a 51% share. PPC has undertaken an expansion programme to facilitate the increase in production.

India

Proved amount in place (hard coal only, million tonnes)	105 820
Proved recoverable reserves (total coal, million tonnes)	60 600
Production (total coal, million tonnes)	515.8

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 northeast: 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 at 1 April 2009, India's geological resources of bituminous coal comprised 105.8 billion tonnes of 'proved resources', 123.5 billion tonnes of 'indicated resources' and 37.9 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.

Considerable uncertainty remains regarding India's coal reserves, particularly as to (i) whether they represent remaining tonnages or need to be reduced by the subtraction of past years' production, and (ii) whether it is appropriate to assess coal resources down to a depth of 1 200 metres, when current coal mines in India do not generally exceed 300 m. Although it is not possible to draw definitive conclusions from the information available, the downside implications of these considerations should be borne in mind.

Lignite deposits mostly occur in the southern State of Tamil Nadu. All-India resources of lignite are quoted in the 11th Five Year Plan as 38.27 billion tonnes as at 1 April 2006, with proved reserves put at 4.5 billion tonnes. About 2.4 billion tonnes in the Neyveli area of Tamil Nadu have been stated to be regarded as 'mineable under the presently adopted mining parameters'. Annual production of lignite is currently in the region of 32 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., mainly 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)	24 100
Proved recoverable reserves (total coal, million tonnes)	28 017
Production (total coal, million tonnes)	353.3

Indonesia has substantial coal resources released according to the annual report of the Ministry of Energy and Mineral Resources as published in 2012. This report indicates a total resource base of nearly 120 billion tonnes, with measured resources totalling 24.1 billion, indicated 27.0, inferred 35.6 and hypothetic 33.5. Within these tonnages, total coal reserves are put at 28 017 million tonnes. It is noteworthy that the proved in place coal resources and recoverable reserves have increased from their 2008 reported levels.

According to the same source 353 million tonnes of coal was produced in 2011 a significant increase from the last report (240 Mt for 2008). 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 2011, approximately 272 million tonnes of coking coal and steam coal were shipped overseas, representing 82% of hard coal production.

Within Indonesia, coal's main market is power generation, which accounted for 56% of internal consumption in 2011.

Kazakhstan

Proved amount in place (total coal, million tonnes)	62 200
Proved recoverable reserves (total coal, million tonnes)	33 600
Production (total coal, million tonnes)	124.7

The Kazakhstan WEC Member Committee reports that at end-2011 the remaining discovered amounts of coal in place were (in billions of tonnes): 24.7 of bituminous coal and 37.5 of lignite, within which the estimated recoverable amounts were 21.5 and 12.1, respectively. It has also provided the following notes on Kazakhstan's coal endowment:

The greater part (63%) of counted (i.e. measured) reserves consists of bituminous coal, found in the Karaganda, Ekibastuz and Teniz-Korzhankol basins, the Kushokinsk, Borly, Shubarkol and Karazhyr deposits, and elsewhere. The remainder (37%) consists of lignite, mainly from the Turgay, Nizhne-Iliyskiy and Maikuben basins.

Kazakhstan coal is characterised by a wide range of metamorphism stages, from gas bituminous coal (GB) up to forge coal (F).

The Karaganda, Ekibastuz and Maikuben basins, and Kushokinsk, Borly, Shubarkol and Karazhyr deposits, as well as some other (small) deposits in various regions of the Republic (where coal mining is presently of insignificant volume, to meet local requirements), are developed and operating.

Distribution analysis of coal reserves and forecast coal resources in regions of the Republic shows that the main part of balance reserves is located in Central Kazakhstan (Karaganda Oblast) and North Kazakhstan (Pavlodar and Kostanay Oblasts). The eastern, western and southern regions of the Republic are in deficit of coal.

After a period of decline in the 1990s, total national output of coal has advanced strongly in recent years. Kazakhstan is a major coal exporter, 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.

Kazakhstan contains central Asia's largest recoverable coal reserves, 3.69% of the world total. is the former Soviet Union's 2nd largest producer, after Russia. According to the Kazakh Ministry of Energy and Natural Resources, the country aims to be producing 100 – 105 million tonnes annually by 2015.

The country has more than 400 coal deposits of which a third are classified as brown coal or lignite deposits. Most coal production is sourced from two main basins, the Karaganda Basin, which supplies coking coal from underground mining operations and the Ekibastuz Basin (the third largest coal basin in the FSU) which supplies coal to the power generation sector. Bogatyr Access Komir, LLP is the largest open cast mining company in Kazakhstan.

The Karazhir deposit is one of Kazakhstan's higher grade coal deposits containing more than 1 billion tonnes of reserves, with a large proportion being open pittable. Several foreign companies are investing in some of Kazakhstan's coal industries.

MMRC owns 32.8 % of the Eurasian Energy Corporation, with the remaining 24.3% by the government and the balance as public and corporate shares.

Ispat-Karmet, Kazakhstan's biggest steel producer, operates several coal mines to feed its steelworks, producing just over 7 Mt from the Karaganda region. Another major producer in Kazakhstan, Bogatyr Access Komir, or BAK, which is wholly owned by the US' Access Industries Inc., owns the Bogatyr mine. The mine has a projected capacity of 50 Mt/y.

New Zealand

Proved amount in place (total coal, million tonnes)	2 719
Proved recoverable reserves (total coal, million tonnes)	571
Production (total coal, million tonnes)	4.9

New Zealand has extensive coal resources, mainly in the Waikato and Taranaki regions of the North Island, and the West Coast, Otago and Southland regions of the South Island. Total in situ coal resources are estimated at around 15 billion tonnes, more than half of which is potentially recoverable. New Zealand coal production in 2010 was 5.33 million tonnes (Mt), 17% up from 2009 production of 4.6Mt. Of this production, approximately 2.60Mt was bituminous, some 2.44Mt was sub-bituminous, and approximately 0.295Mt was lignite. Opencast mines supplied 3.98Mt, with the remaining 1.35Mt from underground mines. Production is centred on the Waikato (2.04Mt), the West Coast (2.71Mt), and Otago/Southland (0.54Mt). Over 59% of national production was from two large opencast operations, at Rotowaro and Stockton.

In 2010, New Zealand consumed some 2.7Mt of coal, again down on the usage of the previous year due to reduced coal-fired generation at Huntly (New Zealand's only one coal-fired power station - The use of this had been scaled back in 2007 in favour of gas; however, the plant was pushed into use again by a particularly dry winter in 2008 impacting on hydroelectricity production). Just over 0.25 million tonnes of coal were imported, mainly for use by Genesis for electricity production, with the remainder coming from local production.

Coal supplied around 5% of New Zealand's consumer energy demand. The biggest domestic users are again the Glenbrook steel mill (0.8 Mt) and the Huntly power station (0.6 Mt). Electricity generation (including cogeneration) accounted for 37.5% of domestic coal use and transformation (mainly steel making) accounted for 19%. The industrial sector, mainly cement plants (Golden Bay Cement near Whangarei and Holcim's plant at Westport), lime and plaster, meat, dairy factories (particularly those at Clandeboye in South Canterbury and Edendale in Southland), wool, timber, and pulp and paper products, accounted for 37% of coal use, and the commercial sector - heating accommodation and service buildings in central and local government, hospitals, rest homes, and educational institutions – accounted for 2.5%. The remaining 4% was used by the agricultural, transport, and residential sectors.

Pakistan

Proved amount in place (total coal, million tonnes)	3 451
Proved recoverable reserves (total coal, million tonnes)	2 070
Production (total coal, million tonnes)	3.9

Pakistan's total coal resource is reported as some 185 billion tonnes, within which 'measured reserves' are 3.45 billion tonnes, 'indicated reserves' nearly 12 billion tonnes, 'inferred reserves' 57 billion and 'hypothetical resources' 113 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 166 of sub-bituminous and 1 904 of lignite.

The bulk (around 99%) of Pakistan's huge coal resource, notably the Thar field, is located in the province of Sindh. 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 ranks of Pakistani coals range from lignite to high-volatile bituminous. The demonstrated Thar coalfield has the largest resources (over 175 billion tonnes in situ) and out of that about 12 billion tonnes are 'demonstrated reserves' (of which 2.7 billion classed as 'measured'). 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.

Poland

Proved amount in place (total coal, million tonnes)	19 274
Proved recoverable reserves (total coal, million tonnes)	5 465
Production (total coal, million tonnes)	130.5

The Polish WEC Member Committee reports that at end-2011 Poland's remaining discovered amount of bituminous coal in place was 17 606 million tonnes, of which 4 178 million tonnes were estimated to be recoverable. The corresponding tonnages for lignite are reported as 1 668 million tonnes in place, of which 1 287 is regarded as recoverable. In both cases the recoverable tonnages relate to established amounts in developed deposits.

The proved amount of hard coal in place is based on a maximum deposit depth of 1 000 m and a minimum seam thickness of 1 m; the corresponding parameters for lignite are a maximum deposit depth of 350 m and minimum seam thickness of 3 m.

Over and above the tonnages quoted above, the Member Committee has advised substantial amounts of both ranks of coal at lower levels of probability, on the basis of a 2009 study. Additional known in situ resources of bituminous grades comprise 26 906 million tonnes classified as 'probable' and 9 193 million tonnes in the 'possible' category, with a further total of some 25.5 billion tonnes potential additional recovery from known resources. Supplementary in situ resources of lignite are reported as 20 995 million tonnes in the 'probable' category and 26 541 million tonnes in the 'possible' category.

Poland's hard coal resources are mainly in the Upper Silesian Basin, which lies in the south-west 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, virtually all through surface mining.

The quality of the Upper Silesian hard coals is generally quite high, with relatively low levels of sulphur and ash content. Of Poland's proved reserves of hard coal, 42.5% is reported to be of coking quality.

Although output of hard coal has declined during the past twenty years, and especially since 1997, Poland is still one of the world's major coal producers (see Table 1.3), with a 2008 output of some 84 million tonnes of hard coal and 60 million tonnes of lignite.

Apart from Russia, Poland is the only world-class coal exporter in Europe. However its 2008 exports fell sharply to less than 8 million tonnes, of which steam coal accounted for 80% and coking coal for 20%. Germany, the Czech Republic and Austria were Poland's largest export markets for coal.

About 63% 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 13%. Almost all lignite production is consumed in CHP plants.

Poland consumes 77 million tonnes of coal per year, which makes it the 10th largest coal consumer in the world and the 2nd largest in the EU, after Germany. 92% of electricity and 89% of heat in Poland is generated from coal and according to the official Polish Government Energy Policy Strategy, coal will remain the key element of the country's energy security until at least 2030.

Although Poland's electricity mix is expected to become more diversified over the coming years, with the first nuclear power plant scheduled for 2022 and rising interest in shale gas exploration, coal is perceived by policy makers as a strategic energy resource for the country's energy security and its consumption is not expected to decline over the next two decades.

According to the "Energy Policy of Poland until 2030" coal is expected to be used as the main fuel for electricity generation. The document envisages a reduction in the energy consumption of the Polish economy and a 19 % share of renewables in total energy consumption by 2020. Nevertheless, electricity consumption in 2030 is expected to increase by 30%, gas consumption by 42% and petroleum products consumption by 7%.

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)	326.5

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 Donetsk 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 km2, 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 km2, 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, totalling about 326 million tonnes in 2008.

Serbia

Proved amount in place (total coal, million tonnes)	20 858
Proved recoverable reserves (total coal, million tonnes)	13 411
Production (total coal, million tonnes)	40.7

Serbia has Europe's largest proven deposits of lignite. The Serbian WEC Member Committee reports that the proved amount of coal remaining in place is nearly 21 billion tonnes, of which by far the greater part (98%) is lignite. Within the other ranks, 9 million out of the 22 million tonnes of bituminous coal in place (41%) is deemed to be recoverable, while the corresponding figures for sub-bituminous are 361 million out of 436 million (83%). The recovery factor attributed to the lignite reserves is approximately 66%. Lignite deposits have been assessed to a maximum depth of 380 metres, with a minimum seam thickness of 10.6 metres.

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

Lignite production is estimated at around 5.5 Mt and bituminous coal production at around 3.6 Mt. The underground Raspotocje Mine at Zenica is one of the larger mines. Lignite, mined in opencast pits, remains one of the main fuels for power generation within the long-term development plans of EPS. In 2010, total power generation in Serbia reached 35.9 TWh of which 25 TWh was based on lignite (69%).

South Africa

Proved amount in place (total coal, million tonnes)	NA
Proved recoverable reserves (total coal, million tonnes)	30 156
Production (total coal, million tonnes)	251

Assessments of South Africa's coal resources remain a moving target. While a number of surveys (e.g. de Jager, 1983; Bredell, 1987; and later studies by the Minerals Bureau) have attempted to quantify the reserves present in each of South Africa's many coalfields, there is not yet total consensus in respect of the tonnages that are currently economically and technologically recoverable.

The figure of 30 156 million tonnes has been adopted as basis for further calculations, based on advice from an expert South African source. This level is derived from the de Jager report, with the individual coalfield reserves adjusted by subtracting cumulative coal production over the period 1982-2008, and then a view being taken of the mineability of coal in major prospective producing areas, in particular the Waterberg coalfield, but also the Springbok Flats, Limpopo and parts of the Free State coalfields. The net outcome is a total for South Africa's proved recoverable coal reserves that is more than one-third lower than the level reported for the 2007 Survey, but that is arguably more realistic in the present circumstances.

Coal occurs principally in three regions:

1. 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;
2. 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;
3. 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 65% 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 27% 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)	2 075
Proved recoverable reserves (total coal, million tonnes)	1 239
Production (total coal, million tonnes)	18

At the end of 2011 Thailand is reported to have proved coal reserves of 1 239 million tonnes. In that same year Thailand had total coal production of 18.0 million tonnes.

Banpu, Thailand's largest coal producer, has entered into a 50:50 joint venture with CLP Powergen Southeast Asia to build a 1,400 MW coal-fired power station at Rayong. The total cost is estimated at USD1.3 billion and Banpu is reported to be seeking to reduce sell off 15-25% of its interest. The company produced 2.5 Mt of lignite in 2003, with sales to the cement industry and power generation utilities.

Thailand is a significant producer of lignite, which is used almost exclusively for power generation. Total national lignite production is around 21 Mt/y. The country currently also imports some 5-6 Mt/y of bituminous coal and some coke for industrial use. The 2,400 MW lignite-fired Mae Moh power plant is the largest source of electricity in the country, generating around 13% of Thailand's electric power production, and also one of the largest point sources of atmospheric pollution in Southeast Asia. The total cost of the project has been estimated at USD1.3 billion, and USD1.1 billion has been received in debt financing from a consortium of financing institutions. Construction began during 2003 and is scheduled for completion in 2006. The project will rely on imported coal. Banpu's mines in Thailand and Indonesia currently have a combined capacity to produce 14.5 Mt/y, with a reserve base of 170 Mt and resources of 139 Mt.

All of Mae Moh's production is consumed by the adjacent 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)	59.7

Ukraine holds the 7th largest coal reserves in the world about 34 billion tonnes and 3rd largest anthracite coal reserves – 5.8 billion tones. Most of the country's coal deposits are located in Donbas basin, Eastern Ukraine. In 2010, Ukraine was the 13th largest coal mining country in the world. Out of 82 mmt of coal mined in 2011, steam coal volume amounted to 62% of total output.

The Majority of produced steam coal in Ukraine is consumed domestically for electricity production. Coal comprised 43.7% of fuel for energy generating companies in 2011, which makes it second most important fuel after nuclear.

Increased demand for steam coal is supported by underutilized capacity of coal-burning TPPs, implementation of pulverized coal injection (PCI) technology at metallurgical plants and increasing export volumes. However, currently Ukraine has a surplus of anthracitic coal, which is mainly exported to Turkey, Bulgaria and Western Europe countries.

Coal production in Ukraine halved over the last 20 years on the back of low demand in the mid-1990s and on a lack of investments into sector's development. Ukraine has a chance to restore former potential implementing successful reforms. In recent years, coal production has increased by 14% – from 72 mmt in 2009 to 82 mmt in 2011 mainly from increased production from private mines. Further increase in mining output is expected after the privatization and modernization of nearly 100 state mines.

Over and above the massive tonnages reported as proved, the WEC Member Committee quoted 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%.

United Kingdom

Proved amount in place (total coal, million tonnes)	386
Proved recoverable reserves (total coal, million tonnes)	228
Production (total coal, million tonnes)	18.1

The country has significant, potentially economic, hard coal resources estimated at 3,000 million tonnes. About 600 million tonnes of reserves are available in existing deep mines or in shallow deposits capable of being extracted by surface mining. In addition, currently inaccessible resources have the potential to provide many years of future production at present levels. There is also about 500 million tonnes of lignite resources, mainly in Northern Ireland, although none is mined or consumed at present.

The UK consumed 64.1 million tonnes of coal in 2012, including 54.9 million tonnes in power stations.

Coal imports to the UK were 44.8 million tonnes, a large increase (+37.7%) on the previous year's amount, mainly as a result of a dramatic increase in electricity generated from coal. Indigenous production was 9.9% less than the previous year at 16.8 million tonnes. (Over the year, 3.0 million tonnes was lifted from stock, compared to 0.8 million tonnes in 2011.)

Coal-fired power stations provided 41% of the UK's electricity (gas 26%, nuclear 20%, others (including renewables) 13%).

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 t/year by 1990.

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. There is now virtually no UK production of coking coal..

The decline of the British coal industry has been accompanied by a sharp decrease in economically recoverable reserves. This assessment, and all other UK coal resources/ reserves data reported by the Member Committee, have been supplied by the Coal Authority, the body which regulates the licensing of British coalmines and performs the residual functions of the former British Coal.

The amount of coal in place that hosts the proved recoverable reserves is put at 386 million tonnes, implying an average recovery factor of 0.59. At lower levels of confidence are a 'probable' amount in place of 262 million tonnes, of which 155 is deemed to be recoverable (also with a recovery factor of 0.59), and a 'possible' in situ tonnage of 2 527 million tonnes, of which 1 396 (55%) is classed as recoverable. A further amount of 1 636 million tonnes is reported by the Member Committee as representing potential additional recovery from known resources. The UK's known resources of coal are dwarfed by its undiscovered resources, with nearly 185 billion tonnes estimated to be in place, of which about 41 billion is deemed to be recoverable.

United States of America

Proved amount in place (total coal, million tonnes)	442 414
Proved recoverable reserves (total coal, million tonnes)	237 295
Production (total coal, million tonnes)	1 092

The United States coal resource base is the largest in the world. The US WEC Member Committee last report states a proved amount in place of some 442 billion tonnes (based on the Energy Information Administration's 'Demonstrated Reserve Base'). This total is comprised of 241.6 billion tonnes of bituminous coal (including anthracite) with a maximum deposit depth of 671 m and minimum seam thickness of 0.25 m; 161.8 billion tonnes of sub-bituminous (at up to 305 m depth and 1.52 m minimum seam thickness) and 39.0 billion tonnes of lignite (at up to 61 m depth and 0.76 m minimum seam thickness).

The reported proved recoverable reserves amount to 237.3 billion tonnes, equivalent to about 28% of the global total. They comprise 108.5 billion tonnes of bituminous coal (including anthracite), 98.6 billion tonnes of sub-bituminous and 30.2 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 0.45, sub-bituminous 0.61 and lignite 0.77. Open-cast or surface mining techniques can be applied to 27.6% of bituminous reserves, to 42.8% of the sub-bituminous and to 100% of the lignite.

On top of the tonnages summarised above, the US WEC Member Committee reports enormous quantities of coal as inferred resources, being the difference between Remaining Identified Resources and the Demonstrated Reserve Base: in total these come to well over a trillion tonnes, composed of 418 billion tonnes of bituminous, 268 billion sub-bituminous and 391 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. Assuming a similar recovery ratio for such resources as for those reported as proved, the US Member Committee estimates the recoverable portion as amounting to some 653 billion tonnes, comprised of 188 bituminous, 163 sub-bituminous and 302 lignite.

Enormous additional (hypothetical) coal resources are also reported. These represent deposits that 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 amounts involved comprise 698 billion tonnes of bituminous coal, 1 036 billion tonnes of sub-bituminous and 296 billion tonnes of lignite, giving a total of some 2 trillion tonnes.

The USA's 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 16% of global production. Coal is the USA's largest single source of indigenous primary energy, although running neck-and-neck with natural gas.

Uzbekistan

Proved amount in place (total coal, million tonnes)	3 000
Proved recoverable reserves (total coal, million tonnes)	1 900
Production (total coal, million tonnes	3.1

Uzbekcoal, the republic's major coal company, quotes Uzbekistan's explored reserves as 1 853 million tonnes of brown coal and 47 million tonnes of black coal. Total coal resources are put at more than 5.7 billion tonnes.

Two coal fields are presently being developed: the Angren brown coal field in the Tashkent region (being exploited by the Uzbekcoal and Apartak companies via open-pit mining) and the Shargun anthracite 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 to over 3 million t/year. According to Uzbekcoal, over 85% of lignite production is consumed by the electric power sector, some after being processed by underground gasification. Bituminous output remains on a very small scale (around 70 000 t/year).

Uzbekistan has listed commercial coal reserves of approximately 3,000 Mt, including 1,000 Mt of bituminous coal. The Angren field contains a proven 1,900 Mt. Uzbekistan's current annual coal requirement is 4 Mt. At present, all of Uzbekistan's coal is produced by JSC Ugol, with over 80% of the production coming from the Angren deposit, situated in the Tashkent oblast. JSC Ugol also has a mining operation at the Shargun mine in the Sukhardaryinskaya oblast. About 70% of Uzbekistan's coal reserves are brown coal/lignite with the remainder bituminous. Coal resources are estimated at over 5 000 Mt, of which 3 000Mt are classified as reserves. Reserves at Angren alone are estimated at over 2 000 Mt, of which most is classified as lignite. Completion of a third mining operation at Baisun could ensure that Uzbekistan has a surplus of coal for export in the future.

Ugol is currently developing two coal deposits, Angren in the Tashkent region and the Shargun pit in Surkhandarya. It is also involved in exploration in the Baisun field in Surkhandarya region.

2

Oil

Contents

Strategic insight

1. Introduction

Oil plays an important role in the global energy balance, accounted for 32% of energy consumption in 2010. This proportion has changed very little in the last 20 years (the figure was 37% in 1990), despite the fact that the total amount of energy consumed worldwide has increased by more than 50% over the same period. This trend has been driven primarily in the last decade by emerging countries.

At regular points throughout these two decades, questions have been raised about the growing scarcity of fossil fuel resources and the imminent inevitability of peak oil.

So what is the status of oil reserves in 2013? What have been the major trends of the past two decades? What can we expect to happen in the near future?

The trend in oil reserves between 1991 and 2011

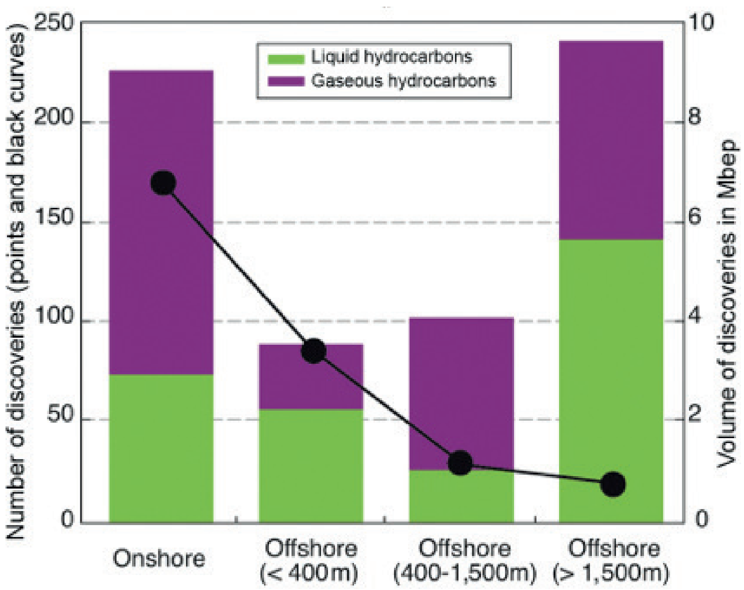
Different sources regularly quoted as benchmarks estimate current global oil reserves at 1,650 billion barrels or Gb (BP Statistical Review). Despite high levels of consumption that have been growing by 32 % since 1991 - from 66 Mbd (million barrels per day) in 1991 to 88 Mbd in 2011 - reserves have increased by 60% over the same period, representing a gain of 620 Gb. Given cumulative consumption of the same order (595 Gb), this means that new discoveries and reappraisals have totaled 1,210 Gb since 1991, which is a large amount by any measure. This explains why the reserves-to-production ratio has increased from 43 to 54 years.

Every region of the world outside Europe saw its oil reserves increase between 1991 and 2011. Those of South America (19.7% of the total), Africa (8%) and the CIS (7.7%) rose most significantly, the first having quadrupled (as a result of the decision of Venezuela to report its huge extra heavy oil resources), whilst the other two doubled over the period. The trend for other regions varied from +77% for North America (13.2% of total as a result of the Canada effect) to 20% for the Middle East (48.1%) and 12% for Asia (2.5%). Europe (0.9%) was the only region to see a decline of 21%.

The increasing importance of South America, whose contribution to total reserves has risen from 7% to nearly 20%, has reduced the influence of the Middle East on the global oil stage. It is true that this region still contains nearly half of the world's oil reserves, but this represents a significant reduction from the 1990s, when the figure was 64%.

On the other hand, one parameter of particular market sensitivity that has changed very little is the dominant role played by OPEC, which still accounts for more than 70% of the world's total reserves, since its members include the two 'heavyweights' of Venezuela (17.9%) and Saudi Arabia (16.1%). Four other Middle Eastern states - Iran, Iraq, Kuwait and the United Arab Emirates - together hold 30% of global oil reserves.

Figure 1
Breakdown of 2011 discoveries by type of deposit
Source: Wood Mackenzie.



2. Technical and economic considerations

The growth in the deep- and ultra-deep offshore

Over the past two decades, ongoing improvements in seismic prospecting systems, geological knowledge, sedimentary basin modeling (reconstituting the geological and oil history of a basin) and production technologies have all broadened the scope of oil exploration. Our knowledge of subsea basins and the continual progress made over the last 50 years in marine exploration and production techniques have led to discoveries at increasing depths and contributed to the emergence of new oil and gas powers.

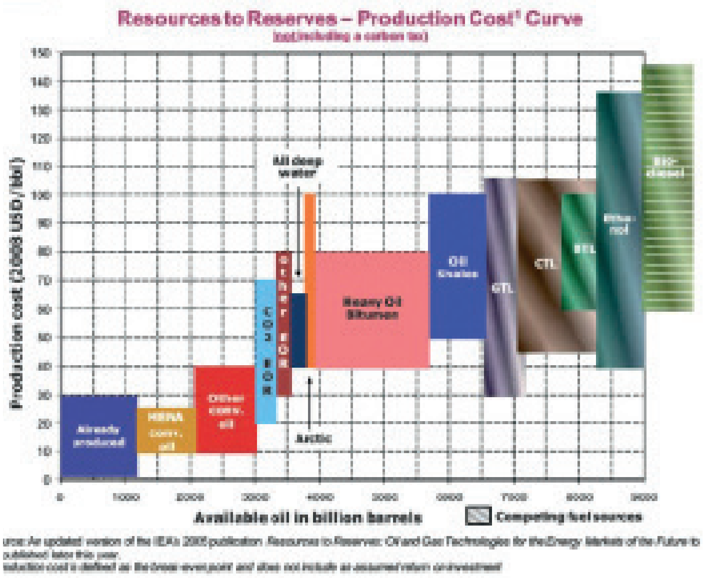
In West Africa, the figures for oil reserves in Nigeria and Angola have risen by 17 Gb and 12 Gb respectively since the start of the 1990s. In Brazil, discoveries in increasingly deep and complex subsea areas have been important the last few years : particular highlights being the Tupi field discovered in 2006 beneath more than 2,000 meters of water and 5,000 meters of sediments, and more recently, the Carioca field. Both deposits contain reserves of several billion barrels of oil equivalent.

In the most recent past, the contribution from the deep- and ultra-deep offshore have become even more important. The 22 discoveries made in 2011 at water depths in excess of 1,500 meters account for two-thirds by volume of all hydrocarbon discoveries for the year (Figure 1).

The increasingly important contribution made by ‘non-conventional’ hydrocarbons.

Although there is no strict definition covering all non-conventional oils and gases, this term is generally considered today to cover all those hydrocarbons that are difficult to extract, either

Figure 2



because they are found in very low permeability horizons, or because their nature makes them difficult to produce. In terms of liquids, this means heavy and extra-heavy oils, tar sands, shale oils and tar shales; for natural gas, it means tight gas from compact reservoirs, coalbed methane gas, shale gas and in the long term methane hydrates.

Over the last twenty years, the growth in non-conventional oils has accounted for a large proportion of the renewal and increase seen in global reserves.

The exploitation of Canadian tar sands (169 Gb of reserves) and heavy and extra-heavy crudes in Venezuela (220 Gb) have contributed very significantly to available reserves in these two countries increasing by a factor of four since the start of the 1990s. At 296 Gb, Venezuela now leads the world in terms of oil reserves, ahead of Saudi Arabia (265 Gb). The volumes available in Canada (total reserves of 175 Gb) outstrip those of both Iraq (143 Gb) and Iran (151 Gb).

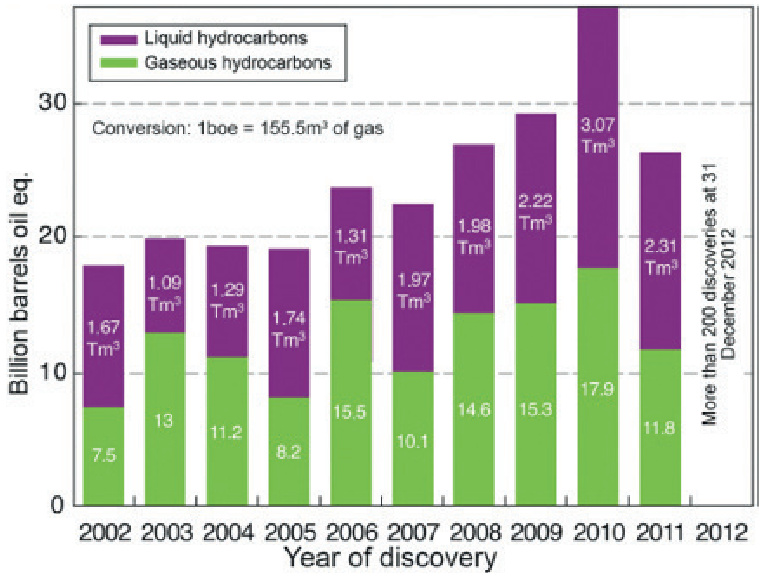
More recently, the development of light tight oils in the USA marks another step change. The growth in source rock oils and the liquid hydrocarbons associated with shale gas are changing the status quo for liquid hydrocarbons by reversing the downward trend that began in the mid-1980s: having fallen from 11 Mbd in 1985 to around 7 Mbd in 2005, volumes have now recovered to approximately 9 Mbd.

The major impact of non-conventionals on the oil price

The increase in production levels of heavy oils from Canada (and to a lesser extent, Venezuela) over the last decade have had a significant effect on trends in the oil price since 2005. In the 1990s, they accounted for only 1% of total supply (0.4 Mbd). They now contribute 7% of the total (3.6 Mbd), half of which are Canadian heavy oils. As shown on the Figure 2 (above), the cost of these non-conventional oils is higher than conventional ones.

The oil price has adjusted rather aggressively to this new reality. In 2011 constant dollar terms, the price of Brent crude rose from an annual average of USD24 per barrel to USD40 per barrel between 1986 (year of the oil price collapse) and 2003. Rising demand from emerging coun-

Figure 3
Estimated new discoveries between 2002 and 2012
Source: Wood Mackenzie.



tries was then a major factor in imposing the necessity for a new price balance in order to develop the non-conventional oils crucial to balance supply with demand. As a result, the oil price rose from USD45 per barrel in 2004 to USD72 per barrel in 2006, reaching USD101 per barrel in 2008. Excluding the effect of the global economic crisis, which brought the price back down to USD64 barrel in 2009, Brent crude is now trading at over USD100 per barrel.

It is true that this USD100+ price per barrel includes a 'geopolitical' component (resulting from the situation in North Africa and the Middle East since 2010), but it also reflects the higher production costs involved in exploiting non-conventional oils, including heavy oils. These costs mean that the minimum tenable price is now estimated at between USD80 and USD90 per barrel.

Over the long term, and contrary to the traditional perception of inexorable price rises, the concept of a new balance at below the USD100 level is now being suggested. The background to this suggestion is the increasing importance of shale oils, whose production cost is estimated at approximately USD50 per barrel in the USA. This scenario is envisageable only on two conditions: a reduction in political tension in sensitive oil-producing regions, and reconsideration of the development of heavy oils in Canada, which are currently setting the minimum benchmark price for the market. Management of the demand side, and specifically the demand from the transport industries, could also see this currently uncertain scenario become a reality at some point in the future.

The increase in prices and investment over the last 10 years

Since the start of the 21st century, rising prices for crude (from USD28 per barrel in 2000 to USD111 per barrel in 2011 for Brent crude) and natural gas has enabled the development of resources previously rated as uneconomic, as well as non-conventional, complex and technical hydrocarbons. With the price of Brent crude remaining sustainably above USD100 per barrel, the exploitation of expensive resources with development costs in the range of USD50 to USD80 per barrel becomes a possibility.

The rise in oil and natural gas prices has also been matched by increased investment in exploration, which totaled nearly USD80 billion in 2012; four times the level of ten years earlier.

This acceleration in exploration activity has contributed to the emergence of new oil and gas producing regions in the Mediterranean (the Levantine Basin) and East Africa (the Rovuma Basin).

Discoveries of conventional oil in the period 2006-2011 averaged 14 Gb per year; a figure equivalent to 40% of consumption over the same period. These volumes are supplemented by the annual revaluations of older discoveries and the development of non-conventional oils. Overall, global oil reserves have increased at a rate close to 4% per annum.

New discoveries of natural gas represented 65% of global consumption over the same period (Figure 3).

3. Market trends and outlook

What is the risk of a future peak?

In the medium term, the relatively high price levels (with the exception of gas prices in the USA) that are enabling the development of costly resources and sustained levels of exploration and production seen in recent years, are likely to ensure that the current trend of bringing new reserves on stream continues.

In the longer term, there is the issue of production leveling out. In terms of liquid hydrocarbons, the IEA published detailed data at the end of 2012 on technically recoverable oil resources (in its WEO 2012). These data identify a potential of 5,870 Gb, which includes 2,200 Gb of conventional oils, 430 Gb of natural gas liquids, 1,880 Gb of heavy and extra-heavy oils and 240 Gb of shale oils. The same IEA report suggest that oil consumption will trend upwards from the *New Policies* benchmark scenario of 32 Gb per year (88 Mbd) in 2011 to 34 Gb (93 Mbd) in 2035. The overall total would therefore be approximately 820 Gb, or 14% of exploitable potential. Assuming stability of consumption beyond 2035 (which remains to be seen), it would take 60 years to consume half of the potential. On the basis of these figures, the risk of reaching a peak in the short term is not very likely.

On the other hand, the conventional oils that account for 25 Gb of production annually will come under increasing - and even very substantial - pressure over the next 10 to 20 years. This will probably be the central challenge for the oil market if demand remains sustained over the next two decades. The practical issue will therefore be one of compensating for this gradual decline by exploiting non-conventional heavy oils and shale oils: this is creating a significant technological and environmental challenge.

Despite unbroken growth in consumption, reserves of hydrocarbons have continued to increase over the last 20 years.

In the short term, the risks of market tension do not lie in those volumes known to be technically and economically accessible, but rather in the unequal distribution of reserves around the world. Today's development of technical and non-conventional hydrocarbons is changing the status quo, as can already be seen in the USA, which is reducing its dependency by developing source rock hydrocarbons.

In the longer term, the slowdown in oil consumption that is already substantial in OECD countries that have introduced energy efficiency measures with particular focus on the transport industries, could lead to a plateau in demand: ‘Peak demand’ rather than ‘Peak oil’.

Olivier Appert
Chairman and CEO of IFP Energies nouvelles
President of the French Energy Council

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Global tables

Table 1
Oil: Proven Recoverable Reserves at end 2011

Country	million tonnes	million barrels
Saudi Arabia	36201	265400
Venezuela	28780	211000
Iran	20624	151200
Iraq	15686	115000
Kuwait	13845	101500
United Arab Emirates	13340	97800
Russian Federation	8184	60000
Libya	6424	47100
Nigeria	5074	37200
United States of America	4215	30900
Kazakhstan	4092	30000
Qatar	3465	25400
Algeria	3170	23241
Brazil	2053	15054
Mexico	1367	10025
Angola	1296	9500
Ecuador	982	7200
Azerbaijan	955	7000
India	777	5700
Oman	750	5500
Norway	726	5320
Sudan	682	5000
Canada	678	4972
Egypt	600	4400
Vietnam	600	4400
Malaysia	546	4000
Indonesia	532	3900
Gabon	505	3700
Australia	450	3300
Yemen	409	3000
United Kingdom	382	2800
Argentina	355	2600
Syria	335	2459
Guinea	232	1700
Congo (Republic of)	218	1600
Chad	205	1500
Brunei Darussalam	150	1100
Equitorial Guinea	150	1100
Denmark	111	811
Turkmenistan	82	600
Uzbekistan	81	594
Peru	79	582

Italy	76	559
Thailand	62	453
Tunisia	55	400
Romania	54	396
Trinidad and Tobago	46	335
Ghana	2	15
China		20400
Colombia		1900
Global Total	**179 682**	**1 339 617**

Table 2
Oil: Production Figures at end 2011

Country	thousand tonnes	thousand barrels
Albania	800	5 864
Algeria	90 700	664 831
Angola	85 000	623 050
Argentina	30 300	222 099
Australia	21 000	153 930
Austria	840	6 157
Azerbaijan	45 800	335 714
Bahrain	10 000	73 300
Bangladesh	300	2 199
Barbados	50	367
Belarus	1 700	12 461
Bolivia	2 300	16 859
Brazil	105 100	770 385
Brunei Darussalam	8 100	59 373
Bulgaria	22	161
Cameroon	3 100	22 723
Canada	63 093	462 472
Chad	6 000	43 980
Chile	200	1 466
China	203 600	1 492 388
Colombia	334	2 449
Congo (DRC)	1 100	8 063
Congo (Republic of)	15 200	111 416
Cote d'Ivoire	1 600	11 728
Croatia	664	4 870
Cuba	3 400	24 922
Czech Republic	165	1 209
Denmark	2 700	19 791
Ecuador	27 100	198 643
Egypt	35 100	257 283
Estonia	600	4 398
Equitorial Guinea	12 500	91 625
Finland	500	3 665
France	900	6 597
Gabon	12 500	91 625
Georgia	100	733
Germany	2 677	19 623
Ghana	3 600	26 388

Greece	100	733
Guatemala	600	4 398
Hungary	700	5 131
India	38 200	280 006
Indonesia	35 327	258 947
Iran	205 800	1 508 514
Iraq	134 200	983 686
Israel	50	367
Italy	5 280	38 702
Japan	707	5 182
Kazakhstan	80 060	586 840
Korea (Republic)	1 000	7 330
Kuwait	134 300	984 419
Kyrgyzstan	100	733
Libya	21 400	156 862
Lithuania	100	733
Malaysia	31 300	229 429
Mauritania	1 300	9 529
Mexico	126 958	930 604
Mongolia	300	2 199
Morocco	50	367
Myanmar (Burma)	900	6 597
Netherlands	1 100	8 063
New Zealand	2 300	16 859
Nigeria	120 200	881 066
Norway	92 200	675 826
Oman	42 100	308 593
Pakistan	3 500	25 655
Papa New Guinea	1 000	7 330
Peru	6 600	48 378
Philippines	800	5 864
Poland	602	4 413
Qatar	64 400	472 052
Romania	4 500	32 985
Russian Federation	509 000	3 730 970
Saudi Arabia	525 800	3 854 114
Serbia	1 032	7 565
Slovakia	500	3 665
South Africa	700	5 131
Spain	100	733
Sudan	22 300	163 459
Syria	16 700	122 411
Taiwan	50	367
Tajikistan	50	367
Thailand	10 400	76 232
Trinidad and Tobago	5 900	43 247
Tunisia	3 700	27 121
Turkey	2 400	17 592
Turkmenistan	10 400	76 232
Ukraine	3 300	24 189
United Arab Emirates	138 400	1 014 472
United Kingdom	52 000	381 160
United States of America	352 300	2 582 359

Uzbekistan	4 100	30 053
Venezuela	154 800	1 134 684
Vietnam	15 900	116 547
Yemen	10 300	75 499
Global total	**3 796 912**	**27 831 366**

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.

Algeria

Proved recoverable reserves (crude oil and NGLs, million barrels)	23 241
2011 production (crude oil and NGLs, thousand b/d)	665
R/P ratio (years)	35.0
Year of first commercial production	1950

Algeria's 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 southeastern parts of the country, with the largest oil field Hassi Messaoud, 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.

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. Published sources generally quote Algeria's reserves as around 12.2 billion barrels, which would appear to exclude NGLs. The bulk of its crude oil exports are consigned to Western Europe and North America.

Angola

Proved recoverable reserves (crude oil and NGLs, million barrels)	9 500
2011 production (crude oil and NGLs, thousand b/d)	623
R/P ratio (years)	15
Year of first commercial production	1956

According to *Oil & Gas Journal* estimates for the end of 2011, Angola had proved reserves of 9.5 billion barrels of crude oil. That figure is the second-largest in Sub-Saharan Africa behind Nigeria, and ranks 18th in the world. Angola's crude oil is light and sweet, making it ideal for export to major world markets like China and the United States. Exploration and production in offshore Angola is advancing at a rapid pace, and foreign investors are beginning to consider some onshore opportunities economically viable. Exports continue to drive Angolan oil production, but the development of new refining capacity could help ease domestic demand shortages that have plagued the country since the end of the civil war in 2002. Prospects for growth in the oil sector are good, but instability and the threat of conflict continue to temper expectations.

Angola's rise as a major oil-producing nation came relatively recently due to the country's long civil war (1975-2002), which restricted exploration in the country. Once Angola began to stabilize its oil production increased dramatically, more than doubling from 896,000 barrels per day (bbl/d) in 2002 to 1.84 million bbl/d of total liquids in 2011. Angola briefly challenged Nigeria as the top oil producer in Sub-Saharan Africa in 2009, but Angola's total liquid production declined slightly in 2010 and again in 2011. Crude oil production in Angola slipped to 1.79 million bbl/d in 2011, but the additions from new projects like the Kizomba Satellites should help Angola reverse that trend. These declines came as a result of regular maintenance and normal decline in the country's older fields, and Angola's government is targeting a return to the 2 million bbl/d production-levels it achieved in 2008 by 2014.

Argentina

Proved recoverable reserves (crude oil and NGLs, million barrels)	2 600
2011 production (crude oil and NGLs, thousand b/d)	222
R/P ratio (years)	11
Year of first commercial production	1907

Argentina is largely self-sufficient in crude oil, but imports oil products. Relatively low levels of exploration activity, combined with natural declines from maturing fields, explain the gradual erosion of oil production from its peak in 1998.Labor unrest has periodically shut-in Argentina's oil production, with concomitant impacts on exports, refinery runs, and local product supply. Separate disruptions affecting up to 100,000 barrels of output per day (bbl/d) plagued the sector in late 2010 and early 2011. The most recent disruption occurred in the Cerro Dragón oil field, which produces about 95,000 bbl/d, or roughly 15 percent of Argentina's total output. Production was significantly curbed at the field in late June when workers went on strike and blocked road access to the field. Negotiations between the field's operator, Pan American Energy (PAE), and labor representatives have reduced tensions and output at the field began to slowly ramp up in July 2012.

Australia

Proved recoverable reserves (crude oil and NGLs, million barrels)	3 300
2011 production (crude oil and NGLs, thousand b/d)	153
R/P ratio (years)	20
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.

The latest data on oil reserves published by Geoscience Australia as a component of its report on the *Oil and Gas Resources of Australia* 2008 (OGRA) relates to the situation as at 1 January 2009. At this point in time there were (in terms of millions of barrels) 881.6 of crude oil, 704.5 of condensate and 749.0 of naturally-occurring LPG in Category 1 (comprising 'current reserves of those fields which have been declared commercial. It includes both proved and probable reserves'). The total crude oil-plus-NGLs figure of 2 335 million barrels compares with the 1 January 2005 total of 2 085 million barrels quoted in OGRA 2004 for this category (which was entitled 'remaining commercial reserves' in another OGRA 2004 table).

Geoscience Australia also provides an alternative assessment, using the McKelvey classification, resulting in 'Economic Demonstrated Resources' (in millions of barrels) of 1 181 crude oil, 2 137 condensate and 1 095 LPG, giving a grand total of 4 413.

According to The *Oil and Gas Journal* (OGJ), Australia had 3.3 billion barrels of proven oil reserves as of January 1, 2011. Australian crude oil is of the light variety, typically low in sulfur and wax, and therefore of higher value than the heavier crudes. The majority of reserves are located off the coasts of Western Australia, Victoria, and the Northern Territory. Western Australia has 64 percent of the country's proven crude oil reserves, as well as 75 percent of its condensate and 58 percent of its LPG. The two largest producing basins are the Carnarvon Basin in the northwest and the Gippsland Basin in the southeast. While Carnarvon Basin production, accounting for 72 percent of total liquids production, is mostly exported, Gippsland Basin production, accounting for 24 percent, is predominantly used in domestic refining.

Azerbaijan

Proved recoverable reserves (crude oil and NGLs, million barrels)	7 000
2011 production (crude oil and NGLs, thousand b/d)	335
R/P ratio (years)	20.9
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. The development of Azerbaijan's offshore oil resources in the Caspian Sea, currently under way, has re-established 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.

Azerbaijan's proven crude oil reserves are estimated at 7 billion barrels in January 2012, according to the *Oil and Gas Journal* (OGJ). The country's largest hydrocarbon basins are located offshore in the Caspian Sea, particularly the Azeri Chirag Guneshli (ACG) field, which accounted for nearly 80 percent of Azerbaijan's total oil output in 2010.

Oil production in Azerbaijan increased from 288,000 barrels per day (bbl/d) in 2000 to 1.1 million bbl/d in 2010. Monthly data through December 2011 show that this year's production thus far has decreased slightly.

Azerbaijan exported an estimated 777,000 bbl/d in 2010, falling by about 8 percent compared with 2009. Although Azerbaijan has three export pipelines, most (about 80 percent) of its oil is exported via the BTC. In addition, small amounts are shipped by truck and railway.

Brazil

Proved recoverable reserves (crude oil and NGLs, million barrels)	15 054
2011 production (crude oil and NGLs, thousand b/d)	770
R/P ratio (years)	19.6
Year of first commercial production	1940

The estimates of Brazil's proved oil reserves reported for previous editions of the SER have been based on the 'measured/indicated/inventoried reserves' published by the Ministério de Minas e Energia in its *Balanço Energético Nacional* (BEN), which broadly equate to 'proved+probable' reserves. For the present *Survey*, the WEC Member Committee for Brazil has been able to supply as a separate item the 'proved' component (8 053) of the BEN 2009 figure of 12 801 million barrels. The remaining amount of 4 748 million barrels is allocated to 'probable' reserves, while the BEN's 'inferred/estimated' category is classified as 'possible'. Of the proved reserves reported by the Member Committee, 93% is located offshore.

The standard published assessments of proved reserves continue to reflect recent generations of the BEN equivalent of 'proved+probable' reserves.

Oil production has followed a strongly upward trend for more than 10 years, reaching an average of 1.9 million b/d in 2008. Much interest is currently being shown in Brazil's offshore (especially deep-water) oil fields and in particular the massive reserves discovered in the pre-salt formation, with production from the Tupi field expected to begin around the end of 2010.

According to the *Oil and Gas Journal* (OGJ), Brazil has 14.0 billion barrels of proven oil reserves in 2012, the second-largest in South America after Venezuela. The offshore Campos and Santos Basins, located off the country's southeast coast, hold the vast majority of Brazil's proven reserves. In 2010, Brazil produced 2.7 million barrels per day (bbl/d) of liquids, of which 75 percent was crude oil. Average liquids production in Brazil contracted slightly in 2011, with modest gains in crude oil production offset by a decrease in ethanol production stemming from a poor sugar cane harvest.

Most Brazilian oil is currently produced in the southeastern region of the country in Rio de Janeiro and Espírito Santo states. More than 90 percent of Brazil's oil production is offshore in very deep water and consists of mostly heavy grades. Six fields in the Campos Basin (Marlim, Marlim Sul, Marlim Leste, Roncador, Jubarte, and Barracuda) account for more than half of Brazil's crude oil production. These Petrobras-operated fields each produce between 100,000 and 350,000 bbl/d.

Brunei

Proved recoverable reserves (crude oil and NGLs, million barrels)	1 100
2011 production (crude oil and NGLs, thousand b/d)	59
R/P ratio (years)	18.7
Year of first commercial production	1929

Brunei is a substantial producer and exporter of crude oil and natural gas for Asia and relies on hydrocarbon revenues for nearly two-thirds of its gross domestic product. Through its long-standing joint venture with Shell, Brunei has produced oil for several decades, primarily from two large, mature fields—Southwest Ampa and Champion—in the offshore Baram Delta. After reaching a recent peak of 220,000 barrels per day (bbl/d) in 2006, Brunei's oil production has declined to 141,000 bbl/d in 2012.

Despite the recent decline in production, Brunei is the largest net exporter of total oil liquids in the Asia-Pacific region given the country's minimal domestic consumption. In 2012, Brunei's net oil exports were around 125,000 bbl/d, mostly in the form of crude oil sent to key Asian oil consumers. Brunei plans to expand its refinery capacity, as Chinese company Zhejiang Hengyi Group is constructing a new refinery with a capacity of 135,000 bbl/d that is scheduled to come online by 2015. This new facility could shift the dynamics of the country's crude exports in favor of consuming more crude and exporting more petroleum products.

Canada

Proved recoverable reserves (crude oil, NGLs, synthetic crude and natural bitumen, million barrels)	4 972
2011 production (crude oil, NGLs, synthetic crude and natural bitumen), thousand b/d)	562
R/P ratio (years)	10.0
Year of first commercial production	1862

The levels of proved recoverable reserves adopted for the present *Survey* correspond with the 'Remaining Reserves as at 2008-12-31' given in the *2008 Report of the Reserves Committee of the Canadian Association of Petroleum Producers* (CAPP) in the CAPP S*tatistical Handbook* (as at February 2010). Reserves comprise 765 million m3 of conventional crude oil, 200 million m3 of natural gas liquids (66 pentanes plus and 134 ethane/propane/butane), and 2 508 million m3 of oil sands and natural bitumen (1 451 'developed mining - upgraded and bitumen' and 1 057 '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 233 million m3 of crude oil. Most of the NGL reserves are located in Alberta.

There is no consensus as regards the treatment of Canadian oil sands/bitumen in compilations of proved oil reserves. Some published compilations (e.g. OPEC, OAPEC, BGR) continue to exclude it entirely, whilst at the other extreme, *Oil & Gas Journal* includes the whole of the ERCB's 'established oil sands reserves'(see above).

The approach adopted for the present *Survey* reflects the practice of the CAPP Reserves Committee and is also broadly comparable with that used by BP in its *Statistical Review of World Energy*, 2009 and by *World Oil* in its annual compilation of *Estimated Proven World Reserves*. BP states that it includes 'an official estimate of 22.0 billion barrels for oil sands under active development', whilst *World Oil* states that its 'oil sands reserve estimate is based on 50 years times current production capacity'.

The quantities of oil sands/bitumen included in Canada's proved reserves adopted for the present Survey correspond with 'remaining established reserves' of 'developed non-conventional oil' at end-2008 published by CAPP in its *Statistical Handbook a*nd included by the Reserves Committee of CAPP in its 2008 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'.

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 Chapter 4: Natural Bitumen and Extra-Heavy Oil.

According to *Oil & Gas Journal* (OGJ), Canada had 173.6 billion barrels of proven oil reserves as of the beginning of 2012. Canada controls the third-largest amount of proven reserves in the world, after Saudi Arabia and Venezuela. Among the top ten reserve-holders, the only other state that is not a member of the Organization of the Petroleum Exporting Countries (OPEC) is Russia. Canada's proven oil reserve levels have been stagnant or slightly declining since 2003, when they increased by an order of magnitude after oil sands resources were deemed to be technically and economically recoverable. The oil sands now account for approximately 170 billion barrels, or 98 percent, of Canada's oil reserves. Aside from other reserves in conventional onshore and offshore producing areas, additional resources are known to be under the Beaufort Sea in the Arctic, off the Pacific coast, and in the Gulf of St. Lawrence.

Canada produced almost 3.7 million barrels per day (bbl/d) of total oil in 2011, an increase of nearly 200 thousand bbl/d from 2010. Of this, 2.9 million bbl/d was crude oil and a small amount of lease condensate.

Oil production in Canada comes from three principal sources: the oil sands of Alberta, the conventional resources in the broader Western Canada Sedimentary Basin (WCSB), and the offshore oil fields in the Atlantic. Production from the oil sands accounted for over half of Canadian oil output in 2011, a proportion that has steadily increased in recent decades. In total, Alberta was responsible for almost 75 percent of Canadian oil production in 2011, according to an analysis of data from Statistics Canada. Other noteworthy producing provinces are Saskatchewan, with almost 14 percent of national output from its share of the WCSB, and offshore areas of Newfoundland and Labrador. Production in conventional offshore reserves off of the eastern provinces comes from mature oilfields, with few opportunities to mitigate decline rates. Accordingly, western provinces are expected to comprise an increasing proportion of overall Canadian oil production in the future.

Chad

Proved recoverable reserves (crude oil and NGLs, million barrels)	1 500
2011 production (crude oil and NGLs, thousand b/d)	43
R/P ratio (years)	34.3
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 (in the initial stages, Bolobo, Komé and Miandoum, followed in 2005-2007 by Nya Moundouli and Maikeri) and the pipeline is handled by a consortium consisting of ExxonMobil (40%), Petronas, the Malaysian state oil company (35%), and ChevronTexaco (25%).

Chad ranks as the tenth-largest oil reserve holder among African countries, with 1.5 billion barrels of proven reserves as of January 1, 2013, according to the *Oil and Gas Journal*. Crude oil production in Chad was an estimated 115,000 barrels per day (bbl/d) in 2011 and 105,000 bbl/d in 2012. Almost all of this was exported via the Chad-Cameroon Pipeline.

China

Proved recoverable reserves (crude oil and NGLs, million barrels)	20 400
2011 production (crude oil and NGLs, thousand b/d)	1492
R/P ratio (years)	13.0
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 northeastern province of Heilongjiang and Shengli (1961) near the Bo Hai gulf.

China's reserves remain a state secret, and thus it is necessary to have recourse to published sources. It is worth noting that OGJ has recently raised its estimate substantially, quoting 20 350 million barrels as at 1 January 2010.

China's oil reserves are by far the largest of any country in Asia: oil output is on a commensurate scale. According to *Oil & Gas Journal* (OGJ), China holds 20.4 billion barrels of proven oil reserves as of January 2012, up over 4 billion barrels from three years ago and the highest in the Asia-Pacific region. China's largest and oldest oil fields are located in the northeast region of the country. China produced an estimated 4.3 million barrels per day (bbl/d) of total oil liquids in 2011, of which 95 percent was crude oil. China's oil production is forecast to rise by about 170 thousand bbl/d to nearly 4.5 million bbl/d by the end of 2013. Over the longer term, EIA predicts a flatter incline for China's production, reaching 4.7 million bbl/d by 2035. China's oil consumption growth eased in 2011 from record high growth of 10 percent in 2010, reflecting the impact of the most recent global financial and economic downturn. However, the country still consumed an estimated 9.8 million bbl/d of oil in 2011, up 400 thousand bbl/d, or over 4 percent from 9.4 million bbl/d in 2010. In 2009, China became the second largest net oil importer in the world behind the United States, with net total oil imports reaching 5.5 million bbl/d in 2011. China's oil demand growth, particularly for petroleum products, hinges on several factors such as domestic economic growth and trade, power generation, transportation sector shifts, and refining capabilities. EIA forecasts that China's oil consumption will continue to grow during 2012 and 2013 at a moderate pace. Even so, the anticipated oil growth of over 0.8 million bbl/d between 2011 and 2013 would represent 64 percent of projected world oil demand growth during the 2-year forecast period.

Colombia

Proved recoverable reserves (crude oil and NGLs, million barrels)	1 900
2011 production (crude oil and NGLs, thousand b/d)	2499
R/P ratio (years)	7.6
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 in recent years and, despite a modest rise in 2008, are still at a very low level in relation to production, according to the data provided to the Colombian WEC Member Committee by the Unidad de Planeación Minero Energético (UPME) of the Ministerio de Minas y Energía. This source quotes proved recoverable oil reserves as 1 458 million barrels, implying an R/P ratio of only 6.4. However, in January 2010 it was reported by ANH (the National Hydrocarbons Agency) that end-2008 reserves were some 1.7 billion barrels.

Colombia's oil production rose at a modest rate from 2003 to 2007, but increased by more than 10% in 2008.

According to The *Oil and Gas Journal* (OGJ), Colombia had about 2 billion barrels of proven crude oil reserves in 2012, up from 1.9 billion barrels in 2011. Colombia's increasing reserves are a result of the exploration of several new blocks that were auctioned in the last bidding round in 2010. Much of Colombia's crude oil production occurs in the Andes foothills and the eastern Amazonian jungles. Meta department, in central Colombia, is also an important production area, predominately of heavy crude oil, and its Llanos basin contains the Rubiales oilfield, the largest producing oil field in the country.

Colombia produced 923,000 barrels per day (bbl/d) of oil in 2011, up 35 percent from the 595,000 bbl/d produced in 2008. This rising production trend is continuing. Most recently, the Ministry of Mines and Energy reported that Colombian production reached 951,000 barrels per day in March 2012, and is expected to reach 1.5 bbl/d by 2020. Colombia consumed 298,000 bbl/d in 2011, allowing the country to export most its oil production.

Congo (Brazzaville)

Proved recoverable reserves (crude oil and NGLs, million barrels)	1 600
2011 production (crude oil and NGLs, thousand b/d)	111
R/P ratio (years)	14.4
Year of first commercial production	1957

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.

As of the end of 2011, Congo has proven oil reserves of 1.6 billion barrels, according to *Oil & Gas Journal* (OGJ), the fifth-largest proven reserves in Sub-Saharan Africa. In the late 1970s, Congo emerged as a significant oil producer. Production continued to expand considerably during the 1990s, but at the turn of the century, as oil fields reached maturity, production declined in 2001. However, from 2008 to 2010 oil production has increased every year as a result of several new projects coming online, mainly Congo's first deepwater field Moho-Bilondo. In 2010, Congo produced 311,000 bbl/d of total oil supply, surpassing the country's previous peak of 292,000 bbl/d in 2000. However, in 2011, as most of Congo's oil fields continued to age, total output fell by about 4 percent to 298,000 bbl/d, of which almost 10,000 bbl/d was natural gas liquids (NGLs) and the remainder was crude oil and lease condensate.The large offshore Moho-Bilondo oil field, operated by Total, is the chief contributor to the increase in production since 2008. It came online in April 2008 and reached plateau output at 90,000 bbl/d in June 2010, according to Total. Total has the majority operating interest of 53.5 percent, in addition to Chevron's 31.5 percent and SNPC's 15 percent. Moho-Bilondo is the country's first deepwater project and marks the largest successful expedition to tap into Congo's deepwater reserves. Additionally, three other oil fields, the Ikalou complex (6,700 bbl/d), Azurite (19,000 bbl/d), and Libondo (12,000 bbl/d), have come onstream since 2008, according to IHS Global Insight and reports from Total.

Denmark

Proved recoverable reserves (crude oil and NGLs, million barrels)	811
2011 production (crude oil and NGLs, thousand b/d)	10
R/P ratio (years)	27
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', 'probable' and 'additional' reserves, but uses the categories 'ongoing', 'approved', 'planned' and 'possible' recovery. The figure for proved reserves (129 million m3 or 811 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 potential additional recovery from known resources has been calculated as the sum of 2 million m3 'planned' reserves and 68 million m3 'possible' reserves, for a total of 70 million m3 or 440 million barrels. The reserve numbers are the expected values in each category.

The Member Committee also reports 60 million m3 (377 million barrels) as estimated to be recoverable from presently undiscovered resources. Denmark's oil reserves and resources may be viewed against the background of its cumulative oil production to end-2008 of some 332 million barrels.

All the oil fields discovered so far are located in the North Sea. Out of 21 fields or areas with reserves in the ongoing/approved category, four (Dan, Halfdan, Skjold and South Arne) account for 75% of the total volume.

The principal fields in production are Halfdan, Dan, Valdemar, South Arne and Gorm, which together accounted for 78% of national oil output. Over 60% of Danish crude is exported, chiefly to other countries in Western Europe.

Ecuador

Proved recoverable reserves (crude oil and NGLs, million barrels)	7 200
2011 production (crude oil and NGLs, thousand b/d)	198
R/P ratio (years)	36.6
Year of first commercial production	1917

The early discoveries of oil (1913-1921) were made in the Santa Elena peninsula on the southwest coast. From 1967 onwards, numerous oil fields were discovered in the Amazon Basin in the northeast 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 republic reactivated its membership of OPEC in October 2007, after suspending it in December 1992.

According to the *Oil & Gas Journal* (OGJ), Ecuador held proven oil reserves of 7.2 billion barrels as of the end of 2011, an increase from the year before. Ecuador claims the third-largest oil reserves in South America after Venezuela and Brazil. Most of Ecuador's oil reserves are in the Oriente Basin in the eastern part of the country, underlying the Amazon.

Ecuador produced an estimated 499,000 bbl/d of oil in 2011, almost all of which was crude. Ecuador's oil production has increased slightly since 2009, but remains below a 2006 peak of 536,000 bbl/d. Thus far in 2012, Ecuador's oil production has fluctuated around 500,000 bbl/d. State-owned companies produced over 70 percent of the country's crude in 2011, with the remainder attributable to fields operated by private companies.

Egypt (Arab Republic)

Proved recoverable reserves (crude oil and NGLs, million barrels)	4 400
2011 production (crude oil and NGLs, thousand b/d)	257
R/P ratio (years)	17.1
Year of first commercial production	1911

Egypt has the sixth largest proved oil reserves in Africa, with over half located in its offshore waters. The main producing regions are in or alongside the Gulf of Suez and in the Western Desert.

Egypt is a member of OAPEC, although its crude oil exports account for less than 10% of its production. Total oil output (including condensate and gas-plant LPGs) has been slowly increasing since 2005.

According to the *Oil and Gas Journal*'s January 2012 estimate, Egypt's proven oil reserves are 4.4 billion barrels, an increase from 2010 reserve estimates of 3.7 billion barrels. New discoveries have boosted oil reserves in recent years. In 2011, Egypt's total oil production averaged around 710,000 bbl/d, of which approximately 560,000 bbl/d was crude oil including lease condensates and the remainder natural gas liquids (NGLs).

After Egypt's production peak of over 900,000 bbl/d in the 1990s, output began to increasingly decline as oil fields maturedHowever, ongoing successful exploration has led to new production from smaller fields, and enhanced oil recovery (EOR) techniques in existing fields have eased the decline at aging fields. In addition, output of NGLs and lease condensate have increased as a result of expanding natural gas production and have offset some of the other declines in liquids production.

One of Egypt's challenges is to satisfy increasing domestic demand for oil in the midst of falling domestic production. Domestic oil consumption has grown by over 30 percent over the last decade, from 550,000 bbl/d in 2000 to 815,000 bbl/d in 2011.

Equatorial Guinea

Proved recoverable reserves (crude oil and NGLs, million barrels)	1 100
2011 production (crude oil and NGLs, thousand b/d)	91
R/P ratio (years)	12
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 U.S. partner United Meridian began producing from Zafiro, another offshore field. Output built up rapidly in subsequent years: crude oil production in Equatorial Guinea . exceeded 360 000 b/d in 2008.

According to the *Oil & Gas Journal*, Equatorial Guinea had proved oil reserves of 1.1 billion barrels as of January 2012. Latest EIA estimates show that Equatorial Guinea's total liquids supply was about 320,000 barrels per day (bbl/d) in 2011. Equatoguinean oil production originates almost entirely from the Zafiro, Ceiba, and Okume fields, while condensate production comes from the Alba field.

Equatorial Guinea's declining output is expected to reverse in 2012, driven by new production from the Aseng field that came on-stream November 2011. Shortly after its start, the field reached around 50,000 bbl/d as four subsea wells were brought online. According to the country's Ministry of Mines, Industry and Energy, production at Aseng, situated in Block 1 offshore Bioko Island, started seven months ahead of schedule and was 13 percent under budget. U.S.-based Noble Energy is the field's main operator and estimates a recovery of about 120 million barrels of liquids over the project's lifespan.

Nearly all of Equatorial Guinea's oil production is exported and the small amount of domestic consumption is met through imports of refined products, which was estimated at 1,000 bbl/d in 2010. The majority of the country's production is exported to markets in North America, Europe, and Asia. In 2010, the United States imported approximately 70,000 bbl/d of crude oil from Equatorial Guinea. Other major destinations for exports include Spain, Italy, and Canada.

Gabon

Proved recoverable reserves (crude oil and NGLs, million barrels)	2 000
2011 production (crude oil and NGLs, thousand b/d)	91
R/P ratio (years)	21
Year of first commercial production	1961

Extensive oil resources have been located, both on land and offshore. In terms of proved recoverable reserves,

According to the *Oil & Gas Journal* (OGJ), Gabon had 2 billion barrels of proven oil reserves as of the end of 2012, the fifth-largest in Sub-Saharan Africa after Nigeria, Angola, Sudan and South Sudan (combined), and most recently, Uganda. Most of Gabon's oil fields are located in the Port-Gentil area and are both onshore and offshore. The country's oil production has decreased by around one-third from its peak of 370,000 barrels per day (bbl/d) in 1997 to 244,000 bbl/d in 2012. Oil consumption has remained steadily low in Gabon, averaging around 14,000 bbl/d over the last decade. Therefore, more than 90 percent of output is exported, or around 250,000 bbl/d, on average over the last decade.

Historically, Gabon's oil production has been concentrated in one large oil field and supported by several smaller fields. As the largest field matured and production declined, a larger field would emerge and replace dwindling production. Dominant fields have included Gamba/Ivinga/Totou (1967-1973), Grondin Mandaros Area (1974-1988), and Rabi (1989-2010). Gabon's greatest success, the Rabi oil field, significantly boosted the country's total output in the 1990s and reached 217,000 bbl/d at its peak in 1997. Although Rabi is still one of Gabon's largest producing fields, it has matured and production has gradually declined to about 23,000 bbl/d in 2010. Since Rabi's descent, a new large field has not yet emerged, since recent exploration has yielded only modest finds.

Gabon ranks third largest in sub-Saharan Africa, after Nigeria and Angola.

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 barrels)	5 700
2011 production (crude oil and NGLs, thousand b/d)	280
R/P ratio (years)	20.3
Year of first commercial production	1890

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 2009, 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 2008-2009 offshore fields provided 66% 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 2008, India produced 34.0 million tonnes of crude oil, plus about 2 million tonnes of natural gasoline and a similar tonnage of gas-plant LPGs, all of which was used internally.

Cairn Energy has made 25 discoveries in Rajasthan (in India's northwest). Initial attention is being concentrated on the Mangala, Bhagyam and Aishwariya (MBA) oil fields. An eventual peak rate of 240 000 b/d is envisaged, subject to Government approval and additional investment.

India was the fourth largest consumer of oil and petroleum products after the United States, China, and Japan in 2011. It was also the fourth largest importer of oil and petroleum products. The high degree of dependence on imported crude oil has led Indian energy companies to attempt to diversify their supply sources. To this end, Indian national oil companies (NOCs) have purchased equity stakes in overseas oil and gas fields in South America, Africa, and the Caspian Sea region to acquire reserves and production capability. However, the majority of imports continue to come from the Middle East, where Indian companies have little direct access to investment.

According to the *Oil & Gas Journal*, India had 5.5 billion barrels of proved oil reserves at the end of 2012. About 53 percent of reserves are from onshore resources, while 47 percent are offshore reserves. Most reserves are found in the western part of India, particularly western offshore, Gujarat, and Rajasthan. The Assam-Arakan basin in the northeast part of the country is also an important oil-producing region and contains more than 10 percent of the country's reserves.

Indonesia

Proved recoverable reserves (crude oil and NGLs, million barrels)	3 900
2011 production (crude oil and NGLs, thousand b/d)	258
R/P ratio (years)	15.2
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.

After being a member since 1962, Indonesia suspended its OPEC membership in December 2008.

Indonesia ranked 20th among world oil producers in 2011 (21st for crude oil and condensate production), accounting for approximately 1 percent of the world's daily production of liquid fuels. With oil first discovered in 1885, the hydrocarbon sector became an important part of Indonesia's economy. The oil and gas industry, including refining, contributed approximately 7 percent to GDP in 2010, according to data from Indonesia's National Bureau of Statistics.

According to the *Oil & Gas Journal* (OGJ), Indonesia had 3.9 billion barrels of proven oil reserves as of January 2012. Total oil production continued to decline from a high of nearly 1.7 million barrels per day (bbl/d) in 1991 to just under 1.0 million bbl/d in 2011. Of this total, approximately 900,000 bbl/d was crude oil and lease condensate production. This fell short of the government's production goal of 945,000 bbl/d for that year (already reduced from an original target of 970,000 bbl/d). While production of refined petroleum products has increased since 1998, crude and condensate production has declined at an annual rate of 3.8 percent between 1998 and 2011.

Iran (Islamic Republic)

Proved recoverable reserves (crude oil and NGLs, million barrels)	151 200
2011 production (crude oil and NGLs, thousand b/d)	1 508
R/P ratio (years)	100
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 100.65 billion barrels of crude oil plus 36.96 billion barrels of NGLs. Total reported reserves are almost identical to those quoted by BP and closely in line with those given by other standard published sources (136.15-138.20), which is possibly somewhat surprising, in that several of these sources specifically exclude natural gas liquids from their compilations.

According to *Oil & Gas Journal*, Iran has nine percent of the world's total reserves and over 12 percent of OPEC reserves.

The Member Committee reports that approximately 14% of Iran's proved reserves of crude and 55% of its NGLs are located offshore. Iran was a founder member of OPEC in 1960. In 2008, about 60% of Iran's crude oil output of 4.1 million b/d was exported, mostly to Europe and Asia.

Over 50 percent of Iran's onshore oil reserves are confined to five giant fields, the largest of which are the Marun field (22 billion barrels), Ahwaz (18 billion barrels), and Aghajari (17 billion barrels). Of those onshore reserves, more than 80 percent are located in the south-western Khuzestan Basin near the Iraqi border. Iran's crude oil is generally medium in sulfur content and in the 28° to 35° API gravity range. According to FACTS Global Energy (FGE), Iran also possesses reserves in the Caspian Sea totaling approximately 100 million barrels. Iran faces continued depletion of its production capacity, as its fields have relatively high natural decline rates (8-13 percent), coupled with an already low recovery rate of around 20-30 percent. Sanctions and prohibitive contractual terms have impeded the necessary investment to halt this decline. Moreover, sanctions enacted in late 2011 and throughout 2012 have accelerated Iran's production capacity declines.

In 2012, Iran produced approximately 3.5 million barrels per day (bbl/d) of total liquids, of which roughly 3.0 million bbl/d was crude oil. The total production level in 2012 was about 17 percent lower than the production level of 4.2 million bbl/d in 2011, most of the drop is attributable to the imposition of sanctions. Condensate production totaled approximately 650 thousand bbl/d in 2011, according to Arab Oil and Gas Directory, of which 440 thousand bbl/d was marketed and 210 thousand bbl/d was mixed in with the crude oil.

Iran has 34 producing fields (22 onshore and 12 offshore), with onshore fields comprising more than 71 percent of total reserves. Currently, Iran's largest producing field is the onshore Ahwaz-Asmari field, followed by the Marun and Gachsaran fields, all of which are located in Khuzestan province.

Iraq

Proved recoverable reserves (crude oil and NGLs, million barrels)	115 000
2011 production (crude oil and NGLs, thousand b/d)	983
R/P ratio (years)	116
Year of first commercial production	1928

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 most of 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. The only exception is *World Oil*, which since end-2006 has estimated Iraq's crude reserves at a somewhat higher level, currently 126 billion barrels.

Iraq was a founder member of OPEC in 1960 and it is also a member of OAPEC. Iraq revised its estimate of proven oil reserves from 115 billion barrels in 2011 to 141 billion barrels as of January 1, 2013, according to the *Oil and Gas Journal*. Iraq's resources are not evenly divided across sectarian-demographic lines. Most known hydrocarbon resources are concentrated in the Shiite areas of the south and the ethnically Kurdish region in the north, with few resources in control of the Sunni minority in central Iraq.

The majority of the known oil and gas reserves in Iraq form a belt that runs along the eastern edge of the country. Iraq has five super-giant fields (over 5 billion barrels) in the south that account for 60 percent of the country's proven oil reserves. An estimated 17 percent of oil reserves are in the north of Iraq, near Kirkuk, Mosul, and Khanaqin. Control over rights to reserves is a source of controversy between the ethnic Kurds and other groups in the area. The International Energy Agency (IEA) estimated that the Kurdistan Regional Government (KRG) area contained 4 billion barrels of proven reserves. However, this region is now being actively explored, and the KRG stated that this region could contain 45 billion barrels of unproven oil resources.

Iraqi crude oil production averaged 3 million barrels per day (bbl/d) in 2012, and Iraq passed Iran as OPEC's second largest crude oil producer at the end of the year. About three-fourths of Iraq's crude oil production comes from the southern fields, with the remainder primarily from the northern fields near Kirkuk. The majority of Iraqi oil production comes from just three giant fields: Kirkuk, the North Rumaila field in southern Iraq, and the South Rumaila field.

Italy

Proved recoverable reserves (crude oil and NGLs, million barrels)	559
2011 production (crude oil and NGLs, thousand b/d)	38
R/P ratio (years)	14.3
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-2008 were 62 million tonnes (equivalent to approximately 434 million barrels), out of a remaining proved amount in place of 128 million tonnes. Recoverable reserves at lower levels of probability comprised 93 million tonnes (651 million barrels) of probable reserves and 104 million tonnes (728 million barrels) of possible reserves. The Member Committee also estimates that undiscovered *in situ* oil resources are in the order of 55 to 370 million tonnes (in round terms, some 400 to 2 700 million tonnes).

Kazakhstan

Proved recoverable reserves (crude oil and NGLs, million barrels)	30 000
2011 production (crude oil and NGLs, thousand b/d)	586
R/P ratio (years)	51.0
Year of first commercial production	1911

Kazakhstan's oil resources are the largest of all the former Soviet republics (apart from the Russian Federation).

The Member Committee reports that more than 90% of the republic's oil reserves are concentrated in its 15 largest oil fields, namely Tengiz, Kashagan, Karachaganak, Uzen, Zhetybai, Zhanazhol, Kalamkas, Kenkiyak, Karazhanbas, Kumkol, Buzachi Severnye, Alibekmola, Prorva Tsentalnaya and Vostochnaya, Kenbai, Korolyovskoye.

Output of oil more than doubled between 2000 and 2008 to some 72 million tonnes (1 554 000 b/d), including condensate and other NGLs. In 2007, exports accounted for about 92% of the republic's oil production.

Kazakhstan's proven oil reserves were estimated at 30 billion barrels by the *Oil and Gas Journal* in January 2012. The country's main oil reserves are located in the western part of the country, where the 5 largest onshore oil fields (Tengiz, Karachaganak, Aktobe, Mangistau, and Uzen) are located. These onshore fields account for about half of current proven reserves, while the offshore Kashagan and Kurmangazy oil fields, in Kazakhstan's sector of the Caspian Sea, are estimated to contain at least 14 billion barrels, with Kashagan accounting for around 9 billion barrels.

Kazakhstan's oil production reached 1.64 million barrels per day (bbl/d) in 2011; however, data for 2012 thus far indicate that liquids production in Kazakhstan will be slightly lower for the year at 1.60 million bbl/d. Kazakhstan's production has seen an impressive expansion since 1995 with the help from foreign oil companies. It surpassed the 1.0 million bbl/d production level in 2003 and steadily grew to be the second-largest oil producer in the Former Soviet Union, second only to Russia.

Kuwait

Proved recoverable reserves (crude oil and NGLs, million barrels)	101 500
2011 production (crude oil and NGLs, thousand b/d)	984
R/P ratio (years)	14
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.

According to *Oil & Gas Journal*, as of January 2011, Kuwait's territorial boundaries contained an estimated 101.5 billion barrels (bbl) of proven oil reserves, roughly 7 percent of the world total. Additional reserves are held in the Partitioned Neutral Zone (aka Divided Zone), which Kuwait shares on a 50-50 basis with Saudi Arabia. The Neutral Zone holds an additional 5 billion barrels of proven reserves, bringing Kuwait's total oil reserves to 104 billion barrels. These reserve estimates have been openly questioned by some analysts and a number of Kuwaiti parliamentarians, with some putting reserves as low as 48 billion barrels.

In 2010, Kuwait's total oil production was approximately 2.5 million barrels per day (bbl/d), including its share of approximately 250,000 bbl/d production from the PNZ. Of the country's 2010 production, approximately 2.3 million bbl/d was crude and 200,000 bbl/d was non-crude liquids. Slightly over half of Kuwaiti crude production in 2010 came from the southeast of the country, largely from the Burgan field; production from the north has increased to approximately 800,000 bbl/d. As a member of OPEC, Kuwait's total production is constrained by the organization's production targets, which in 2010 meant the country maintained about 320,000 bbl/d of spare crude oil production capacity. In early 2011, as one of the few OPEC members with spare capacity, Kuwait has increased oil production to compensate for the loss of Libyan supplies

Libya/GSPLAJ

Proved recoverable reserves (crude oil and NGLs, million barrels)	47 100
2011 production (crude oil and NGLs, thousand b/d)	1 546
R/P ratio (years)	30
Year of first commercial production	1961

Libya accounts for about one-third of Africa's proved oil reserves. 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 35o API) and very low in sulphur.

Libya joined OPEC in 1962 and is also a member of OAPEC. It exported over 80% of its oil output in 2008, mostly to Western Europe.

According to *Oil and Gas Journal* (OGJ), Libya had total proven oil reserves of 47.1 billion barrels as of January 2012 – the largest endowment in Africa, and among the ten largest globally. Close to 80 percent of Libya's proven oil reserves are located in the eastern Sirte basin, which also accounts for most of the country's oil output. Libyan oil is generally light (high API gravity) and sweet (low sulfur content).

Prior to the onset of hostilities, Libya had been producing an estimated 1.65 million barrels per day (bbl/d) of mostly light, sweet crude oil. Libya's production capacity had increased over the previous decade, from 1.4 million bbl/d in 2000 to 1.8 million bbl/d in 2010, but still remained well below peak levels of over 3 million bbl/d achieved in the late 1960s. Though Libya produced below nameplate capacity, output exceeded the country's OPEC target of 1.47 million bbl/d. Libya also produced an estimated 140 thousand bbl/d of non-crude liquids, which include lease condensate and natural gas plant liquids.

Malaysia

Proved recoverable reserves (crude oil and NGLs, million barrels)	4 000
2011 production (crude oil and NGLs, thousand b/d)	229
R/P ratio (years)	17.4
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.

For a number of years, there appears to have been considerable uncertainty with regard to the level of Malaysia's proved oil reserves.

According to the *Oil & Gas Journal* (OGJ), Malaysia held proven oil reserves of 4 billion barrels as of January 2011. Nearly all of Malaysia's oil comes from offshore fields. The continental shelf is divided into 3 producing basins: the Malay basin offshore peninsular Malaysia in the west and the Sarawak and Sabah basins in the east. Most of the country's oil reserves are located in the Malay basin and tend to be of high quality. Malaysia's benchmark crude oil, Tapis Blend, is of the light and sweet variety with an API gravity of 44° and sulfur content of 0.08 percent by weight.

Total oil production in 2011 was an estimated 630,000 barrels per day (bbl/d), compared with 665,000 in 2010, of which about 83 percent was crude oil. More than half of total Malaysian oil production currently comes from the Tapis field in the offshore Malay basin. Malaysian oil production has been gradually decreasing since reaching a peak of 862,000 bbl/d in 2004 due to its maturing reservoirs. Malaysia consumes the majority of its oil production and domestic consumption has been rising as production has been falling. The government is focused on opening up new investment opportunities by enhancing output from existing fields and developing new fields in deepwater areas offshore Sarawak and Sabah.

Mexico

Proved recoverable reserves (crude oil and NGLs, million barrels)	10 200
2011 production (crude oil and NGLs, thousand b/d)	930
R/P ratio (years)	10.9
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.

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.

Mexico produced an average of 2.96 million barrels per day (bbl/d) of total oil liquids during 2011. Crude oil accounted for 2.55 million bbl/d, or 86 percent of total output, with the remainder attributable to lease condensate, natural gas liquids, and refinery processing gain. Mexico's oil production has been relatively stagnant since 2009, and the minor decreases that have occurred mark an improvement from the more drastic declines that commenced around the middle of the last decade. Mexico is a large but declining net crude exporter, and is a net importer of refined petroleum products. Its most important trading partner is the United States, which is the destination for most of its crude oil exports and the source of most of its refined product imports.

According to the *Oil & Gas Journal* (OGJ), Mexico had 10.2 billion barrels of proven oil reserves as of the end of 2011. Most reserves consist of heavy crude oil varieties, with the largest concentration of reserves occurring offshore in the southern part of the country, especially in the Campeche Basin. There are also sizable reserves in Mexico's onshore basins in the northern parts of the country.

Nigeria

Proved recoverable reserves (crude oil and NGLs, million barrels)	37 200
2011 production (crude oil and NGLs, thousand b/d)	881
R/P ratio (years)	42.2
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.

Nigeria exports much the greater part of its crude oil output, chiefly to North America and Western Europe, and imports the bulk of its refined product requirements.

According to *Oil and Gas Journal* (OGJ), Nigeria has an estimated 37.2 billion barrels of proven oil reserves as of the end of 2011. The majority of reserves are found along the country's Niger River Delta and offshore in the Bight of Benin, the Gulf of Guinea, and the Bight of Bonny. Current exploration activities are mostly focused in the deep and ultra-deep offshore with some activities in the Chad basin, located in the northeast of the country.

The government hopes to increase proven oil reserves to 40 billion barrels in the next few years; however, exploration activity levels are at their lowest in a decade and only three exploratory wells were drilled in 2011, compared to over 20 in 2005. Rising security problems related to oil theft, pipeline sabotage, and piracy in the Gulf of Guinea, coupled with investment uncertainties surrounding the long-delayed PIB, have curtailed oil exploration projects and impeded the country from reaching its ongoing target to increase production to 4 million bbl/d.

Norway

Proved recoverable reserves (crude oil and NGLs, million barrels)	5 320
2011 production (crude oil and NGLs, thousand b/d)	675
R/P ratio (years)	7.8
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 remaining oil reserves at end-2008 amounted to 7 491 million barrels, comprised of 919 million m3 (5 780 million barrels) of crude oil, 120 million tonnes (1 440 million barrels) of NGLs and 43 million m3 (270 million barrels) of condensate. 'Remaining reserves' are defined as 'remaining recoverable petroleum resources in deposits for which the authorities have approved the plan for development and operation (PDO) or granted a PDO exemption'. They 'also include petroleum resources in deposits that the licensees have decided to develop, but for which the authorities have not as yet completed processing of either a PDO approval or a PDO exemption'.

In addition to 'remaining reserves', 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 688 million m3 (4 327 million barrels) of crude oil, 42 million tonnes (502 million barrels) of NGLs and 32 million m3 (201 million barrels) of condensate - a total additional recoverable resource of just over 5 billion barrels. Over and above these amounts, the NPD estimates that Norway possesses about 9.6 billion barrels of 'undiscovered resources', comprising 1 260 million m3 (7 925 million barrels) of crude oil and 265 million m3 (1 667 million barrels) of condensate. Undiscovered resources include 'petroleum volumes expected to be present in defined plays, confirmed and unconfirmed, but which have not yet been proven by drilling'.

As a frame of reference, it may be noted that Norway's cumulative oil production to the end of 2008 consisted of 3 405 million m3 (21 417 million barrels) of crude oil, 116 million tonnes (1 386 million barrels) of NGLs and 96 million m3 (604 million barrels) of condensate, for a grand total of 23 407 million barrels of oil, compared with its total remaining discovered and undiscovered oil resources of 22 106 million barrels.

Following 16 years of unremitting growth, Norwegian oil production levelled off in the late 1990s and since 2001 has followed a gently downward path. Nearly 84% of Norway's 2008 crude oil production of some 2.1 million b/d was exported, mostly to Western European countries, Canada and the USA.

According to The *Oil and Gas Journal* (OGJ), Norway had 5.32 billion barrels of proven oil reserves as of January 1, 2012, the largest oil reserves in Western Europe. All of Norway's oil reserves are located offshore on the Norwegian Continental Shelf (NCS), which is divided into three sections: the North Sea, the Norwegian Sea and the Barents Sea. The bulk of Norway's oil production occurs in the North Sea, with smaller amounts in the Norwegian Sea and new exploration and production activity occurring in the Barents Sea.

In June 2012, Norway's oil and gas production faced being completely shut-in when an offshore workers strike began over employers' plans to increase the retirement age from 62 to 67. Government intervention stopped the strike, during which cutbacks to the country's production affected 15 percent of oil and 7 percent of gas production, according to Statoil.

In 2011, Norway produced 2.0 million bbl/d of petroleum and other fuels, of which about 87 percent was crude oil. Norway's petroleum production has been gradually declining since 2001 as oil fields have matured. The NPD expects that production will continue to decline slowly over the next few years, and that in the longer term the number and size of new discoveries will be a critical factor in maintaining production levels. Currently, seventy fields are in production on the NCS. The three largest producing oil fields are Ekofisk, which produced 162,000 bbl/d in 2010; Grane, which produced 166,000 bbl/d; and Troll, which produced 118,000 bbl/d.

According to the International Energy Agency (IEA), Norway exported an estimated 1.45 million bbl/d of crude oil in 2011, of which 90 percent went to OECD European countries. The top five importers of Norwegian oil (crude plus products) in 2011 were the United Kingdom (52 percent), the Netherlands (18 percent), the United States (10 percent), France (8 percent), and Germany (5 percent).

Oman

Proved recoverable reserves (crude oil and NGLs, million barrels)	5 500
2011 production (crude oil and NGLs, thousand b/d)	308
R/P ratio (years)	17.7
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 (5.5 billion barrels at end-2008, according to OAPEC). Other published sources of reserves data generally concur.

Three oil fields were discovered in the northwest 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.

According to *Oil & Gas Journal* (OGJ), Oman has total proven reserves of 5.5 billion barrels of oil as of January 2012. Oman's reserves are found mainly in the north and central onshore areas, comprised of disparate clusters of smaller fields. This geological composition makes production costs some of the highest in the region. The transition into secondary and tertiary extraction techniques will only increase these costs further. Oman has thus far implemented a successful program to reverse the decline in production experienced for most of the past decade, deploying some of the most sophisticated methods of enhanced oil extraction.

Oman produced 889,000 barrels per day (bbl/d) of total petroleum liquids in 2011, 886,000 bbl/d of which was crude oil. Oman is expected to produce 915,000 bbl/d for 2012 after its Harweel Enhanced Oil Recovery project adds approximately 30,000 bbl/d to that total. Oil production in Oman has increased by more than 24 percent over the past four years, from a low of 714,000 bbl/d in 2007. PDO owns a concession which previously encompassed most of the country (Block-6), which has since been broken up and parceled out in successive bidding rounds. Much of the production growth has come from the success of international firms in developing former portions of Block-6.

Papua New Guinea

Proved recoverable reserves (crude oil and NGLs, million barrels)	70
2011 production (crude oil and NGLs, thousand b/d)	7
R/P ratio (years)	10
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.

Peru

Proved recoverable reserves (crude oil and NGLs, million barrels)	582
2011 production (crude oil and NGLs, thousand b/d)	48
R/P ratio (years)	12.1
Year of first commercial production	1883

Peru is probably the oldest commercial producer of oil in South America.

According to the *Oil and Gas Journal*, Peru had 582 million barrels of proven oil reserves in January 2012, up from 533 million barrels in January 2011. Peru has added approximately 50 million barrels of reserves in each of the past two years.

Much of Peru's proven oil reserves are onshore, and the majority of these onshore reserves are in the Amazon region. Eleven important new hydrocarbon discoveries have occurred in just the past few years. In 2005, Peru's first offshore oil discovery occurred in the San Pedro well in Block Z-2B, where light oil was found. The largest recent discoveries have been in the offshore Talara and onshore Maranon basins, where 1.4 billion and 970 million barrels, respectively, of recoverable oil have been discovered.

Oil companies have leased at least 41 percent of the Peruvian Amazon for oil and gas drilling and could soon hold 70 percent, including areas that are officially protected for the indigenous people, as more contracts are signed with foreign investors. The current exploration boom is the second to hit this region, following an initial surge of exploration in the 1970s and 1980s.

According to EIA estimates, Peru produced 153,800 barrels per day (bbl/d) of total oil in 2011, down slightly from the 158,300 bbl/d produced in 2010, and an increase of 60 percent from the 99,600 bbl/d produced in 2000. According to Perupetro, of the 153,000 bbl/d produced in 2011, 46 percent was crude oil and 54 percent was natural gas liquids (NGL).

Peru is a net oil importer of both crude and products as domestic petroleum consumption is increasing and reached 189,000 bbl/d in 2010. Much of Peru's crude oil imports come from Ecuador.

Qatar

Proved recoverable reserves (crude oil and NGLs, million barrels)	25 400
2011 production (crude oil and NGLs, thousand b/d)	472
R/P ratio (years)	53.4
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.

According to *Oil & Gas Journal*, as of January 1, 2013, Qatar has 25.4 billion barrels of proven oil reserves, ranked 13th in the world. According to official OPEC data, Qatar was the 10th largest total liquids exporter among the 12 OPEC members in 2011. The onshore Dukhan field, located along the west coast of the peninsula, is the country's oldest producing oil field, although it has been surpassed in production by the offshore Al-Shaheen field. While the government's energy policy is focused on gas production and exports, Qatar is taking measures to extend the life of its oil fields through enhanced oil recovery (EOR) techniques.

In 2011, Qatar consumed approximately 183,000 bbl/d of petroleum. Although still relatively small compared to total production levels, consumption has more than tripled since 2000. FACTS Global Energy forecasts Qatar's oil product consumption to grow by an average annual rate of about five percent between 2010 and 2015. Qatar's increased petroleum consumption rate is due to its rapidly growing economy, particularly the associated growth of transportation sector demand.

Romania

Proved recoverable reserves (crude oil and NGLs, million barrels)	396
2011 production (crude oil and NGLs, thousand b/d)	32
R/P ratio (years)	12.2
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 recoverable reserves of 54 million tonnes of crude plus 0.54 million tonnes of NGLs. The estimated additional recoverable reserves reported comprise 9 million tonnes of 'probable' reserves and 6 million tonnes in the 'possible' category, together with minor tonnages of NGLs.

The principal region of production has long been the Ploesti area in the Carpathian Basin to the northwest 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 figure of proved recoverable reserves given above, 2.2 million tonnes of crude oil is reported to be located in offshore waters. In national terms, oil output (including NGLs) has been gradually contracting since around 1995.

Russian Federation

Proved recoverable reserves (crude oil and NGLs, million barrels)	60 000
2011 production (crude oil and NGLs, thousand b/d)	3730
R/P ratio (years)	16.8
Year of first commercial production	NA

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.

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 upward trend starting in 2000 brought the total up to 488.5 million tonnes (nearly 9.9 million b/d) in 2008. Russia exports more than half of its oil production.

Russia's proven oil reserves were 60 billion barrels as of January 2012, according to the *Oil and Gas Journal*. Most of Russia's resources are located in Western Siberia, between the Ural Mountains and the Central Siberian Plateau and in the Volga-Urals region, extending into the Caspian Sea. Eastern Siberia holds some reserves, but the region has had little exploration.

In 2011 Russia produced an estimated 10.2 million bbl/d of total liquids (of which 9.8 million bbl/d was crude oil), and consumed roughly 3.1 million bbl/d. Russia exported around 7 million bbl/d in 2011 including roughly 4.9 million bbl/d of crude oil and the remainder in products. Russia's pipeline oil exports fall under the jurisdiction of the state-owned pipeline monopoly, Transneft. Monthly data thus far in 2012 show that Russia's total liquids production has consistently remained above 10.0 million bbl/d.

Russia has 40 oil refineries with a total crude oil processing capacity of 5.4 million bbl/d, according to *Oil and Gas Journal*. Rosneft, the largest refinery operator, controls 1.3 million bbl/d and operates Russia's largest refinery, the 385,176-bbl/d Angarsk facility. Other companies with sizeable refining capacity in Russia include LUKoil (975,860 bbl/d), and TNK-BP (690,000 bbl/d).

In 2011, Russia exported roughly 7.1 million bbl/d of total liquids. Data for 2011 show that Russia exported about 4.8 million bbl/d of crude oil in 2011. The majority of Russian exports (78 percent) are destined for European markets, particularly Germany, Netherlands, and Poland. Around 16 percent of Russia's oil exports go to Asia, while 6 percent are exported to North and South America. Russia's main export blend is the Urals blend and it is a mixture of mostly Russian crudes of varying quality and smaller amounts of Azeri and Kazakh crudes.

Saudi Arabia

Proved recoverable reserves (crude oil and NGLs, million barrels)	265 400
2011 production (crude oil and NGLs, thousand b/d)	3864
R/P ratio (years)	68.8
Year of first commercial production	1938

NOTE: Saudi Arabia data include its share of the 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-2008 these represented about 21% 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.

Saudi Arabia was a founder member of OPEC and also of OAPEC. It exports about 80% of its crude oil output; major destination regions are Asia, North America and Western Europe.

According to the *Oil and Gas Journal*, Saudi Arabia contains approximately 265 billion barrels of proven oil reserves (plus 2.5 billion barrels in the Saudi-Kuwaiti shared Neutral Zone) as of January 1, 2013, amounting to slightly less than one-fifth of proven, conventional world oil reserves. Although Saudi Arabia has about 100 major oil and gas fields, over half of its oil reserves are contained in only eight fields. The giant Ghawar field, the world's largest oil field with estimated remaining reserves of 70 billion barrels, has more proven oil reserves than all but seven other countries.

Saudi Arabia is the largest oil consuming nation in the Middle East. Saudi Arabia consumed approximately 3 million barrels per day (bbl/d) of oil in 2012, almost double 2000 levels, because of strong industrial growth and subsidized prices. Contributing to this growth is rising direct burn of crude oil for power generation, which reaches 1 million bbl/d during summer months, and the use of natural gas liquids (NGL) for petrochemical production. Khalid al-Falih warned that domestic liquids demand was on a pace to reach over 8 million bbl/d (oil equivalent) by 2030 if there were no improvements in energy efficiency.

Saudi Arabia produced on average 11.6 million bbl/d of total petroleum liquids in 2012. In addition to 9.8 million bbl/d of crude oil, Saudi Arabia produced 1.8 million bbl/d of natural gas liquids (NGL) and other liquids. Saudi Arabia, a leading world producer of NGL, has experienced a rise in demand for NGL from developing countries, including India (the leading export destination), where it is used for cooking and transportation.

Sudan

Proved recoverable reserves (crude oil and NGLs, million barrels)	5 000
2011 production (crude oil and NGLs, thousand b/d)	480
R/P ratio (years)	38.1
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.

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.

Most of Sudan's oil is produced in the South, but the pipeline, refining and export infrastructure is in the North of the country. According to the *Oil & Gas Journal* (OGJ), Sudan and South Sudan had five billion barrels of proved oil reserves as of January 2012, up from an estimated 563 million barrels in 2006. Other analysts put reserve estimates as low as 4.2 billion barrels (Wood Mackenzie) or as high as 6.7 billion barrels (BP 2011 Statistical Review). The majority of reserves are located in the oil-rich Muglad and Melut Basins. Oil produced in these basins and nearby fields is transported through two main pipelines that stretch from the landlocked South to Port Sudan. Due to civil conflict, oil exploration prior to independence was mostly limited to the central and south-central regions of the unified Sudan. Natural gas associated with oil production is mostly flared or re-injected. Despite known reserves of 3 trillion cubic feet (Tcf), gas development has taken the backseat to oil development and gas exploration has been limited.

Syria (Arab Republic)

Proved recoverable reserves (crude oil and NGLs, million barrels)	2 459
2011 production (crude oil and NGLs, thousand b/d)	351
R/P ratio (years)	19.1
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.

National oil output has declined in recent years; according to the National Bureau of Statistics. Syria is a member of OAPEC: exports accounted for about 40% of its crude oil production in 2007, with its principal customers being Germany, Italy and France.

The *Oil & Gas Journal* (OGJ) estimated Syria's proved reserves at roughly 2.5 billion barrels as of January 1, 2013, a total larger than all of Syria's neighbours except for Iraq. Much of Syria's crude oil is heavy and sour, making the processing and refining of Syrian crudes difficult and expensive. Further, as a result of sanctions placed on Syria by the European Union in particular—which accounted for the vast majority of Syrian oil exports previously—there are limited markets available that can import and process the heavier crudes produced in Syria. As such, Syrian government revenues are severely limited by the loss of oil export capabilities, particularly the lost access to European markets, which in 2011 imported USD3.6 billion worth of oil from Syria according to news reports.

In 2011, Syrian total petroleum consumption was 258,000 barrels per day (bbl/d) while total production was 330,800 bbl/d, but the country has limited refining capacity and therefore must import refined products. Sanctions, and the resulting loss of oil export revenues, make importing such products difficult, although several countries continue to pursue energy deals with Syria, including Iraq, Iran, Russia, and Venezuela.

Thailand

Proved recoverable reserves (crude oil and NGLs, million barrels)	453
2011 production (crude oil and NGLs, thousand b/d)	325
R/P ratio (years) (see below)	5.3
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 that, after cumulative production to the end of 2008 of 463 million barrels of crude oil, Thailand's remaining proved oil reserves were some 182 million barrels of crude, plus 271 million barrels of condensate. Approximately 70% 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 of 232 000 b/d in 2008.

Further recoverable amounts (in millions of barrels) reported by the Member Committee consist of 422 probable reserves of crude oil and 337 of condensate, plus 176 possible reserves of crude and 134 of condensate. The total of recoverable reserves of crude oil of some 780 million barrels is closely matched by the corresponding total for condensate (742 million barrels). Total output of oil (crude oil, condensate and other NGLs) has more than doubled since 1999, with an average of 325 000 b/d in 2008. Exports have declined since 2006 to an average of about 40 000 b/d.

According to *Oil & Gas Journal*,Thailand held proven oil reserves of 453 million barrels in January 2013, an increase of 11 million barrels from the prior year. In 2011, Thailand produced an estimated 393,000 barrels per day (bbl/d) of total oil liquids, of which 140,000 bbl/d was crude oil, 84,000 bbl/d was lease condensate, 154,000 bbl/d was natural gas liquids, and the remainder was refinery gains. Thailand consumed an estimated 1 million bbl/d of oil in 2011, leaving total net imports of 627,000 bbl/d, and making the country the second largest net oil importer in Southeast Asia.

Thai oil production has risen in the last few years, although production remains well below consumption levels. About 80 percent of the country's crude oil production comes from offshore fields in the Gulf of Thailand. Chevron is the largest oil producer in Thailand, accounting for nearly 70 percent of the country's crude oil and condensate production in 2011. The largest oilfield is Chevron's Benjamas located in the north Pattani Trough. The field's production peaked in 2006 and declined to less than 30,000 bbl/d in 2010. Chevron is developing satellite fields to sustain production around Benjamas. PTTEP's Sirikit field is another significant crude oil producer supplying 22,000 bbl/d of oil in 2010. Small independent companies, Salamander Energy and Coastal Energy, began exploring onshore and shallow water fields including Bualuang, Songkhla, and Bua Ban that came online in 2009.

Trinidad & Tobago

Proved recoverable reserves (crude oil and NGLs, million barrels)	335
2011 production (crude oil and NGLs, thousand b/d)	149
R/P ratio (years)	11.1
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. Its remaining recoverable reserves are small in regional terms. Trinidad's probable reserves of oil are 335 million barrels and possible reserves a further 1 561 million barrels, making the republic's 3P oil reserve just over 2.5 billion barrels.

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 southeast tip of the island).

Turkmenistan

Proved recoverable reserves (crude oil and NGLs, million barrels)	600
2011 production (crude oil and NGLs, thousand b/d)	205
R/P ratio (years)	8.0
Year of first commercial production	1911

This republic has been an oil producer for nearly a century, with a cumulative output of more than 5 billion barrels. According to *Oil & Gas Journal*, echoed by OAPEC and BP, its proved reserves are some 600 million barrels. 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.

Turkmenistan had proven oil reserves of roughly 600 million barrels in January 2012 based on estimates by *Oil and Gas Journal* (OGJ). Most of the country's oilfields are situated in the South Caspian Basin and the Garashyzlyk onshore area in the west of the country. In addition, Turkmenistan claims its section of the Caspian Sea contains 80.6 billion barrels of oil, though much is unexplored.

Turkmenistan's oil production has increased from 110,000 bbl/d in 1992 to approximately 202,000 barrels per day (bbl/d) in 2010. Production peaked at 213,000 bbl/d in 2004 before declining slightly. Short-term forecasts keep production relatively flat through 2013. About half of production is slated for the domestic market that consumed slightly more than 100,000 bbl/d.

Uganda

The independent oil company Tullow Oil is seeking to develop (in conjunction with two prospective partners) a number of promising oil fields that have been discovered in the vicinity of Lake Albert. Production from the Kasamene field, to serve industrial consumers within Uganda, is expected to commence by the end of 2011. Full exploitation of the deposits might require the construction of an export pipeline to the Indian Ocean coast, although other possibilities are being examined.

United Arab Emirates

Proved recoverable reserves (crude oil and NGLs, million barrels)	97 800
2011 production (crude oil and NGLs, thousand b/d)	2 980
R/P ratio (years)	89.7
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.

A member of the Organization of the Petroleum Exporting Countries (OPEC) since 1967, the UAE is one of the most significant oil producers in the world. According to *Oil & Gas Journal* 2012 estimates, the UAE holds the seventh-largest proved reserves of oil in the world at 97.8 billion barrels, with the majority of reserves located in Abu Dhabi (approximately 94 percent). The other six emirates combined account for just 6 percent of the UAE's crude oil reserves, led by Dubai with approximately 4 billion barrels. Production of these resources is dominated by the state-owned Abu Dhabi National Oil Company (ADNOC) in partnership with a few large international oil companies under long-term concessions. The impending expiration of two existing concession licenses could create opportunities for new entrants into the UAE's energy sector. The ADNOC-led consortia continue to keep the UAE near the top of the list of the world's largest crude oil producers, ranking seventh in 2011 at 2.7 million barrels per day (bbl/d).

With the world's seventh-largest proved reserves of crude oil (97.8 billion barrels), the UAE holds more than 7 percent of the world total. Nevertheless, recent exploration has not yielded any significant discoveries of crude oil. What it lacks in new discoveries, however, it makes up for with an emphasis on EOR techniques designed to extend the lifespan of the Emirates' existing oil fields. By improving the recovery rates at those fields, such techniques helped the UAE to nearly double the proved reserves in Abu Dhabi over the last decade-plus. These gains helped make the UAE the seventh-largest oil producer in the world in 2011, producing 2.7 million bbl/d of crude. Production targets are set by the Organization of the Petroleum Exporting Countries (OPEC), and any increase of UAE's output requires approval from fellow members.

The Zakum system—the third-largest oil system in the Middle East and the fourth-largest in the world—is the center of the UAE's oil industry, accounting for nearly 30 percent of the country's total production in 2010. The Upper Zakum field is run by the ZADCO—which is owned by ADNOC (68 percent share), ExxonMobil (28 percent), and the Japan Oil Development Company (JODCO; 12 percent)—and currently produces 550,000 bbl/d. In July 2012, ZADCO awarded an USD800-million engineering, procurement, and construction contract to Abu Dhabi's National Petroleum Construction Company—along with French firm Technip—with the goal of expanding production to 750,000 bbl/d by 2016. The Lower Zakum field operated by the Abu Dhabi Marine Operating Company (ADMA-OPCO) is also being expanded, with production expected to reach 425,000 bbl/d; up from the 300,000 bbl/d it currently produces.

United Kingdom

Proved recoverable reserves (crude oil and NGLs, million barrels)	3 100
2011 production (crude oil and NGLs, thousand b/d)	1 526
R/P ratio (years)	5.5
Year of first commercial production	1919

Proved recoverable reserves, as reported by the UK WEC Member Committee, are based on a report by the Department of Energy and Climate Change (DECC) entitled *UK Oil and Gas*

According to *Oil & Gas Journal* (OGJ), the UK had 3.1 billion barrels of proven crude oil reserves as of January 2013, the most of any EU member country. In 2012, the UK produced 1.0 million barrels per day of oil (bbl/d) and consumed 1.5 million bbl/d.

The vast majority of UK's reserves are located offshore in the UK continental shelf (UKCS), and most of the oil production occurs in the central and northern sections of the North Sea. Although there is a modest amount of oil produced onshore, in 2012 more than 90 percent of total UK production took place offshore.

In 2012, UK produced approximately 1 million bbl/d of liquid fuels, of which about 881,000 bbl/d was crude oil. The 2012 liquid fuels production level was about 14 percent lower than the 2011 production level, and it reached the lowest production level since the 1970s. EIA's Short-Term Energy Outlook expects UK oil production to continue to decline, remaining below 1 million bbl/d through the end of 2014. The main reason for this decline is the overall maturity of the country's oil fields and diminishing prospects for new substantial discoveries in the future. Although its proximity to major consuming markets makes UK exploration attractive, recent increases in taxes will continue to affect the attractiveness of the UK fields in the longer term.

Despite the large declines in oil production over the last few years, the UK is still one of the largest petroleum producers and exporters in Europe. In 2011, the UK exported approximately 690,000 bbl/d. Export data published by UK's Her Majesty's Revenue and Customs show that the vast majority (82 percent) of crude oil exports were destined to EU countries, mainly Germany and Netherlands.

The United Kingdom is also a significant oil importer, receiving more than 1 million bbl/d in 2011. According to UK's Her Majesty's Revenue and Customs, the majority (67 percent) of the imports came from Norway, a decline from the 72-percent share the previous year. The remainder of UK oil imports came from Russia (8 percent), Nigeria (7 percent), and the Middle East (2 percent).

United States of America

Proved recoverable reserves (crude oil and NGLs, million barrels)	30 900
2011 production (crude oil and NGLs, thousand b/d)	6 734
R/P ratio (years)	11.5
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.

The Energy Information Administration of the US Department of Energy states that proved oil reserves are

Uzbekistan

Proved recoverable reserves (crude oil and NGLs, million barrels)	594
2011 production (crude oil and NGLs, thousand b/d)	111
R/P ratio (years)	14.6
Year of first commercial production	NA

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

Since the late 1990s total oil output has followed a downward trend, falling by 80 000 b/d, or 42%, in the space of ten years. All of Uzbekistan's production of crude and condensate is processed in domestic refineries or used directly as feedstock for petrochemicals.

As mentioned above The *Oil and Gas Journal* (OGJ) estimates that Uzbekistan had 594 million barrels of proven oil reserves in 2012, 171 discovered oil and natural gas fields, 51 of which produce oil and 17 of which produce gas condensates. Uzbekistan's petroleum production consists of roughly 60 percent high-sulfur crude and 40 percent condensates from natural gas fields. Existing oil and gas fields are depleting faster than new discoveries are coming online, spurring the need for further investment.

Because of ageing infrastructure and a dearth of foreign investment and capital, production rapidly declined after 2003. During 2010, Uzbekistan produced 59,000 barrels of oil per day (bbl/d), a 60-percent decline from 2000 levels.

Uzbekistan will remain a net oil importer as long as production declines. Oil demand exceeds supply by nearly two-fold. Domestic oil consumption reached an estimated 139,000 bbl/d in 2010 and has remained relatively constant since the mid-1990s, averaging 150,000 bbl/d. However, the country's goal is to lower oil import dependence and increase exports.

Venezuela

Proved recoverable reserves (crude oil and NGLs, million barrels)	211 000
2011 production (crude oil and NGLs, thousand b/d)	2 566
R/P ratio (years)	>100
Year of first commercial production	1917

Venezuela's oil resource base is truly massive, and proved recoverable reserves are by far 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 northeast and Oriental in eastern Venezuela. The country has been a global-scale oil producer and exporter ever since the 1920s, and was a founder member of OPEC in 1960.

According to *Oil and Gas Journal* (OGJ), Venezuela had 211 billion barrels of proven oil reserves in 2011, the second largest in the world. This number constitutes a major upward revision – two years ago the same publication listed the country's reserves at 99.4 billion barrels. The update results from the inclusion of massive reserves of extra-heavy oil in Venezuela's Orinoco belt. Reserves could be even bigger at 316 billion barrels, with further investigation from the "Magna Reserva" project.

In 2010 the country had net oil exports of 1.7 million barrels per day (bbl/d), the eighth-largest in the world and the largest in the Western Hemisphere. While crude oil production for 2011 increased 100,000 bbl/d (and equaled 2009 levels), overall production levels have declined by roughly one-quarter since 2001. Natural decline at older fields, maintenance issues, and the need for increasing foreign investment are behind this trend. In addition, net oil exports have also declined since domestic consumption has increased 39% since 2001.

EIA estimates that the country produced around 2.47 million bbl/d of oil in 2011. Crude oil represented 2.24 million bbl/d of this total, with condensates and natural gas liquids (NGLs) accounting for the remaining production. Estimates of Venezuelan production vary from source to source, partly due to measurement methodology. For instance, some analysts directly count the extra-heavy oil produced in Venezuela's Orinoco Belt as part of Venezuela's crude oil production. Others (including EIA) count it as upgraded syncrude, whose volume is about 10 percent lower than that of the original extra-heavy feedstock.

Vietnam

Proved recoverable reserves (crude oil and NGLs, million barrels)	4 400
2011 production (crude oil and NGLs, thousand b/d)	317
R/P ratio (years)	40.5
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.

Published estimates of Vietnam's oil reserves vary widely. *Oil & Gas Journal* assumes entirely different figures compared to other assessments, quoting only 600 million barrels, which implies the very low R/P ratio of 5.5.

Production of crude oil began in 1986 and rose steadily until 2004, but subsequently has fallen to only about 300 000 b/d, all of which is presently exported. Output of NGLs is of minor proportions, at around 15 000 b/d.

According to *Oil & Gas Journal* (OGJ), Vietnam now ranks third in terms of proven oil reserves for the Asia-Pacific region. Vietnam held 4.4 billion barrels of proven oil reserves as of January 2012, which was significantly higher than 0.6 billion barrels of oil in 2011. This increase is in part a result of Vietnam's efforts to intensify exploration and development of its offshore fields. Ongoing exploration activities could increase this figure in the future, as Vietnam's waters remain relatively underexplored.

Vietnam's oil production increased steadily until 2004, when it peaked above 400,000 barrels per day (bbl/d). Since 2004, oil production has slowly declined, reaching an estimated 326,000 bbl/d in 2011. EIA forecasts that the country's oil production will rise by around 50,000 bbl/d within the next 2 years, based on several smaller fields anticipated to come online by 2015. These fields should offset declining production from mature basins, but Vietnam must accelerate exploration efforts to maintain current production levels in the longer term. A fraction of Vietnam's oil production, almost 20 bbl/d in 2011, is in the form of natural gas liquids (NGLs).

In 2010, Vietnam consumed 320,000 bbl/d of oil, and EIA estimates demand to increase to more than 400,000 bbl/d in 2013, reflecting the economic growth and industrial developments within Southeast Asia. EIA estimates consumption surpassed production in 2011.

One of the most active areas for ongoing exploration and production activities in Vietnam is the offshore Cuu Long Basin. Vietnam's oil production has decreased over the last seven years primarily as a result of declining output at the Bach Ho (White Tiger) field, which accounts for about half of the country's crude oil production. After reaching peak output of 263,000 bbl/d in 2003, the field's production dropped to an average 92,000 bbl/d in early 2011. It is expected that Bach Ho's production decline rate will range from 20,000 bbl/d to

25,000 bbl/d through 2014. Vietsovpetro intends to boost oil production by using water injection to stem declines of aging fields and by investing USD7 billion on exploration activities over the next five years.

Vietnam is currently a net exporter of crude oil but remains a net importer of oil products. According to EIA, oil demand has nearly doubled in the past decade from 175,000 bbl/d in 2000 to an estimated 320,000 bbl/d in 2010. Vietnam still needs to import about 70 percent of refined products and petrochemicals since the output from the Dung Quat refinery does not satisfy domestic demand. As more refineries are scheduled to come online, PetroVietnam anticipates meeting 50 to 60 percent of the domestic product demand by 2015. FACTS Global Energy forecasts that domestic petroleum product demand will more than double by 2030 to nearly over 830,000 bbl/d from around 375,000 bbl/d in 2011. The transportation sector, which uses gasoline, diesel, jet fuel, and fuel oil for rail, drives about 60 percent of petroleum product demand. The remaining oil product demand originates from liquefied petroleum gas (LPG) use in the residential sector and small amounts of products used in the industrial and power sectors.

Yemen

Proved recoverable reserves (crude oil and NGLs, million barrels)	3 000
2011 production (crude oil and NGLs, thousand b/d)	317
R/P ratio (years)	23.0
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.Oil production peaked in 2002 and has since followed a consistently downward path. Total output in 2008 was 317 000 b/d (including 24 000 b/d of gas-plant LPG). About 70% of Yemen's crude production is exported, largely to Singapore, Japan, Korea Republic and other Asia/Pacific destinations

According to the *Oil & Gas Journal*, Yemen had proven crude oil reserves of 3 billion barrels as of January 1, 2012. Yemen's oil reserves and production are located in five main geographical areas: Jannah and Iyad in central Yemen, Marib and Jawf in the north, and Shabwa and Masila in the south. All production comes from two sedimentary basins, Marib-Shabwa and Sayun-Masila, out of a total of 12 basins believed to hold reserves. Yemen's oil reserves are generally light and sweet (low in sulfur content) at API gravities ranging from 28 degrees to 48 degrees, with the highest quality crude coming from the Marib-Jawf fields.

In 2011, Yemen's total oil production averaged about 170,000 barrels per day (bbl/d), down from 259,000 bbl/d estimated for 2010. Production has been declining steadily since reaching a peak of 440,000 bbl/d in 2001 due to a lack of sufficient new investment in exploration and inadequate maintenance of facilities.

Yemen had total oil exports of 103,000 bbl/d and total domestic consumption of 157,000 bbl/d in 2010, according to EIA estimates. Asian markets account for the majority of Yemen's oil exports. With growing domestic consumption and decreasing production, net exports are on a declining trend. Yemen imports some refined products; in 2008, the most recent data available, gross imports of refined products were estimated at 62,000 bbl/d, mainly distillate and residual oils, while 18,000 bbl/d of products were exported.

Unconventional oil

Shale Oil

Introduction

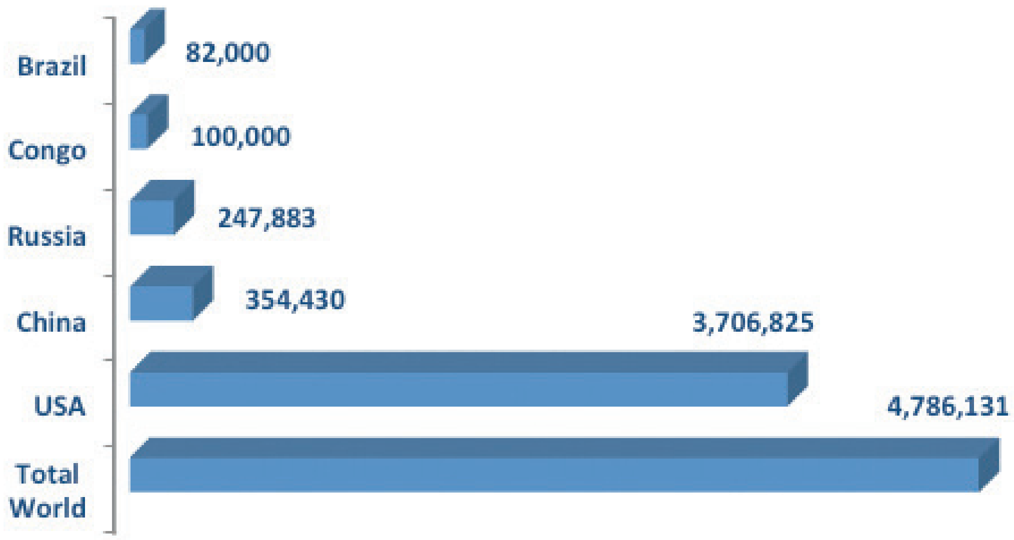
This section on oil shale is based on the findings of the 2013 report.

While the overall global demand for oil is growing, the reserves to production ratio for oil has remained at the same level of approx. 40 years for the past three decades thanks to continued new discoveries and more efficient technologies which allow higher oil recovery rates. Moreover, huge resources of unconventional oil will ensure the availability of oil for decades to come.

In the changing global oil landscape, the United States is emerging as an oil superpower. In addition to being the highest oil consuming nation, USA is the world's second largest crude oil producer after Saudi Arabia, and its oil shale endowment accounts for about 75% of the world total.

The recent success of shale gas in the United States can be considered a good example of how advances in technologies can turn the market upside down transforming North America from the largest gas importing region into a potential net exporter of gas.

Figure 1
Oil Shale resources (million barrels): Top 5 countries in 2011.
Source: WEC World Energy Resources, 2013



Definition and current applications

What is oil shale? Oil shales are fine-grained sedimentary rocks containing relatively large quantities of organic matter (known as 'kerogen') from which significant volumes of shale oil and combustible gas can be produced. The use of oil shale can be traced back to ancient times. Common products made from oil shale were kerosene/lamp oil, paraffin wax, fuel oil, lubricating oil and grease, naphtha, illuminating gas, and the fertiliser chemical, ammonium sulphate. As the number of automobiles and trucks was increasing rapidly in the early 1900s, the feared shortage of motor fuels was looming in peoples' minds. This led to the search of substitutes for petrol and made use of oil shale in transport.

Oil shale can be used in various ways from electricity generation via direct combustion to production of a wide range of petrochemical goods, including shale oil and other liquid fuels. Shale oil can be used as a direct substitute for conventional crude oil, and therefore it seems likely that in the coming years the fast growing demand and potentially higher prices for conventional oil will result in a rise in the demand for shale oil. Some forecasts indicate that oil shale can account for more than a third of the growth in use of unconventional oil by 2030.

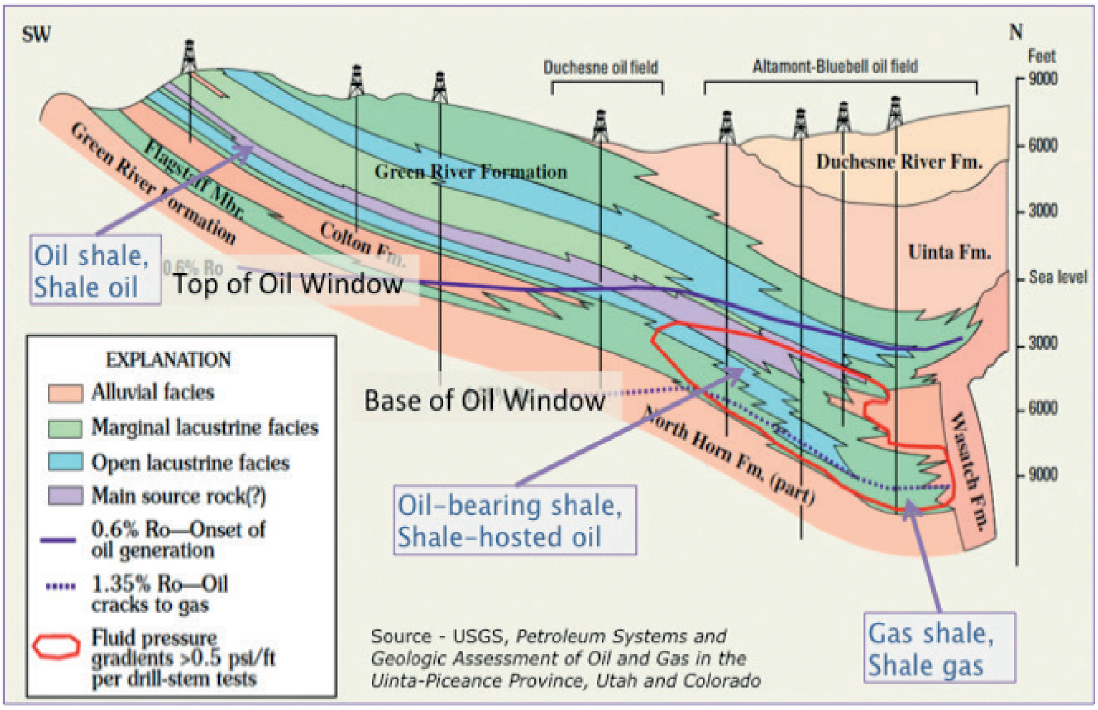
Conceptual Oil Shale Development Issues

According to the WEC's World Energy Resources survey, proven oil reserves have increased during 1987-2007 by 17% and proven gas reserves by 38%.

Figure 2 shows a schematic cross-section through the Uinta Basin of Utah, which serves to illustrate a terminological issue that has dogged discussion of shale-hosted hydrocarbon resources for some years now. It shows approximate depths for both the oil and gas windows and highlights a section of the Green River Formation that consists of oil shale at

Figure 2

Schematic cross-section showing the relationship of oil shale, oil-bearing shale and gas shale and the related hydrocarbon resources derived from them



shallow depth, but is responsible for half of Utah's oil production where it lies in the oil window. Deeper still, it might be considered a gas shale.

One of the first things most people hear about oil shale is that it is a misnomer because there is not oil in the rock. This is the equivalent of saying it is wrong to call Cabernet Sauvignon a wine grape because there is no wine in it.

The terms oil shale (for the rock) and shale oil (for the retorted product) have been well-understood for more than one hundred years now. These two terms have been consistently applied to the fine-grained organic-rich rock that only yields its petroleum product on heating either at the surface or at depth.

The development of shale gas from gas shale formations (like the Barnett and Marcellus formations) created another pair of terms for a different unconventional resource and its host rock. But when the liquid rich part of these formations (and other formations containing mainly liquids) began to be developed, even technical people ignored the technical priority of shale oil as the product of retorting oil shale.

Massive confusion about the size and impact of these different but distinctly related resources arose. Oil-bearing shale and shale-hosted oil have been suggested as alternative terms for the rock formation and the product for the Bakken and Eagle Ford and their relatives. Others in industry are now calling this group of products and plays "Tight Oil," in part because the oil commonly resides in silty or chalky units interbedded with or adjacent to the organic rich source shale, but that would not generally be called shale.

But this approach leaves a gap with respect to the rock term. You could say "tight-rock oil," but this still has no good generic equivalent for the rock formations (like oil shale and gas shale) that explorationists will be looking for.

Oil shale development in specific economic niches

As the capital requirements for oil shale development projects are very high, and the infrastructure and facilities involved very complex, it is likely that oil shale development will not advance until economics or security demands require it.

Estonia – Longstanding production, engineering know-how, and lack of other resources have driven Estonia to develop both power and oil production from oil shale. Today, companies also have begun active export marketing campaigns targeted at USA, Jordan, Morocco and the Ukraine.

Brazil – Petrobras has investigated the potential for development using its own technology in Jordan, the U. S. and Morocco. Although they are currently far more directed at large offshore oil and gas developments, another company, using a modified version of the PetrosixTM retort, is proposing to produce shale oil for a niche market within Brazil, and investigating the application of the new system to other countries. Initial development started when traditional reserves were sparse, and accompanied aggressive development of biofuel capability.

China – Currently the largest producer of oil from oil shale, China has been building retorts at a remarkable pace. The resource is very large, and research is being directed at both surface and in situ retorts.

Oil shale is unlikely to meet the skyrocketing demand for energy of this developing country, but it will continue to be a contributor.

Australia – Production of shale oil is only in demonstration mode at present. The discovery of large gas reserves have overshadowed the technical progress of shale oil due to the indication that these reserves may include significant shale-hosted oil plays. Nevertheless, it appears that the tide may have turned with the lifting of a moratorium on shale oil production, and development is proceeding.

Active Developers

Israel – Israel Energy Initiatives is bringing in situ technology to bear on the only significant onshore resource for oil production. They are also actively exporting technology through parent Genie Oil in,for example, a recent agreement with the Mongolian government.

Jordan – Like Israel, endowed with few traditional resources, and impacted economically by large bills for imported fuel, and also by subsidies of a low-income population, Jordan has worked hard and made agreements with a diverse group of companies to develop both oil and power production, employing both surface and in situ methods. If successful, these projects will make Jordan an important producer.

Mongolia – Recent agreement with Genie Oil, and the presence of Total and at least two other companies interested in oil shale, Mongolia is showing itself eager to develop an indigenous energy source.

Morocco – With the active participation of the government's Organization National des Hydrocarbures et des Mines, Morocco is working with several companies to develop oil shale to move away from total dependence on other Arab countries' oil and gas.

Oil shale resource assessment

Although information about many oil shale deposits around the world is rudimentary at best, the potential resources of oil shale are enormous. The absence of statistics and formal assessments however makes it difficult to produce reliable estimates, and these estimates can change significantly after discoveries of new deposits. Total world resources of shale oil currently are conservatively estimated at 4.8 trillion barrels. This is almost 4 times more than the crude oil resources which stand at 1.3 trillion barrels. However, economically recoverable oil shale reserves are much lower.

Oil shale resources are widely distributed around the world. Some 40 countries have registered about 300 deposits, with the USA accounting for approx. 77% of world resources. In the Middle East, only Jordan and Israel are reporting oil shale data, with Jordan estimating its reserves at 28 billion and Israel at 79 billion barrels. In Jordan, deposits are distributed over 26 sites and located near the surface, thus reducing exploitation costs.

China undertook its first national oil shale evaluation in 2004-2006. It confirmed that there is a vast and widespread resource across 47 basins and 80 deposits with the total estimated in-place shale oil resource of 354 billion barrels. Nearly 70% of the deposits are located in Eastern and Middle China. Current shale oil production is in North-East China

Russia has the third largest oil shale resources in the world after USA and Brasil. The total resource of oil shale is estimated at 43,41 bln t. The oil shale deposits in Russia are located in the Baltic basin, in the East of the European part of the country – and in the North-Eastern part of Siberia. There are more than 80 oil shale deposits identified in Russia.

Sizeable deposits of oil shale have been discovered in various parts of Israel and current estimates of the theoretical reserves total some 12 billion tonnes.

However, a recently released fact sheet by the US Geological Survey highlights the fact that much of this amount is contained in rock of such low grade that it is likely to be a long time before it is utilized (See Figure 3). About 1.2 trillion barrels of the resource is contained in rocks that would be considered better than marginal (≥15 gal/tonne), the main part of it in the Piceance Creek Basin of Colorado and about 400 billion barrels of the resource are contained in rocks considered high grade (≥25 gal/ton). Assessments of oil shale deposits require more detail than assessment of any other global resource because of the variety of shales.

This requirement most certainly holds back many other countries with potential deposits of oil shale,

This requirement most certainly holds back many other countries with potential deposits of oil shaledue to the high costs of assessments and also lack of domestic expertise in this area.

Changes in the growth trajectory of shale-hosted oil production

The two most prominent oil-bearing shale plays in the United States at present are the Bakken and the Eagle Ford. Daily production rates for these two fields are shown in Figure 3a. Plotted on the semi-logarithmic grid where a straight line indicates exponential growth, it is obvious that the North Dakota Bakken shows three curves, each starting with a minor drop in the production rate.

During the first period of 2.25 years of the recent economic boom, production rose by about 6% per month. In response to steadily rising oil prices, it then accelerated to nearly 11% per month. However, after a drastic price drop in late 2008, the production growth rate dropped back to about 4% per month, despite a fairly rapid recovery of oil price. The break in slope occurred at about 100,000 barrels per day as at that stage the pressure reached the point where further growth would require additional production capacity.

This appears to have been driven by the strong capital constraints at the time, and possibly by at least some companies reaching a point where most land was held by production

Figure 3a shows daily oil production from the Bakken Formation in North Dakota and the Eagle Ford Formation in Texas.

Figure 3b shows that, during this time, production increases appear to have undergone three upward spikes followed by extended, erratic decline, ending with negative growth values.

Figure 3c shows a similar declining trend for the monthly growth rate for the Eagle Ford over much of the life of this boom. It is worth noting that the gas production from the Eagle Ford has declined by a third over the last year (driven, presumably by price drops). In both cases, if the long term pattern remains above 1% per month (>12% per year) it will still be impressive growth. Most important, is that the exploitation of these shales has produced a massive impact on the global market by increasing the diversity of supply and economic options for many importing nations.

The two most prominent oil-bearing shale plays in the United States at present are the Bakken and the Eagle Ford. An interesting development can be noted: while tracking the production growth of these two plays over the past year. Daily production rate for these two fields is shown on Figure 3a.

Figure 3

Distribution of the US oil shale resource (Total Resource: 4291 billion barrels)

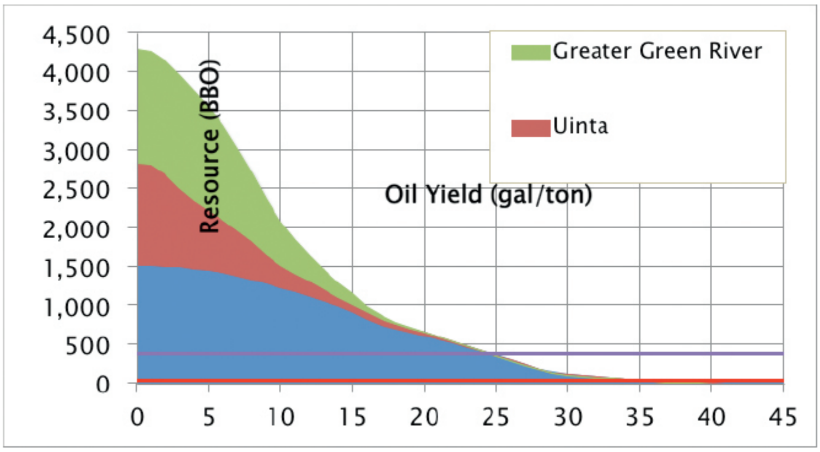


Figure 3a

Daily oil production from the Bakken Formation in North Dakota and the Eagle Ford Formation in Texas. Average monthly production increase for the Bakken are shown in the legend in parentheses

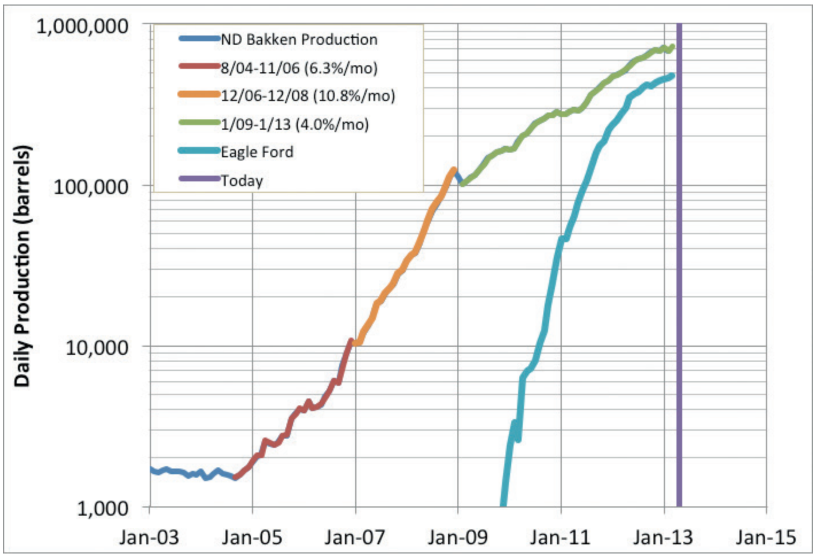


Figure 3b

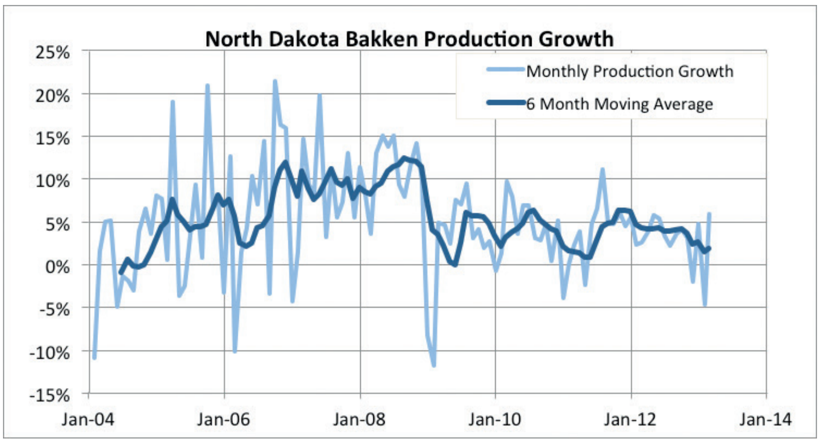
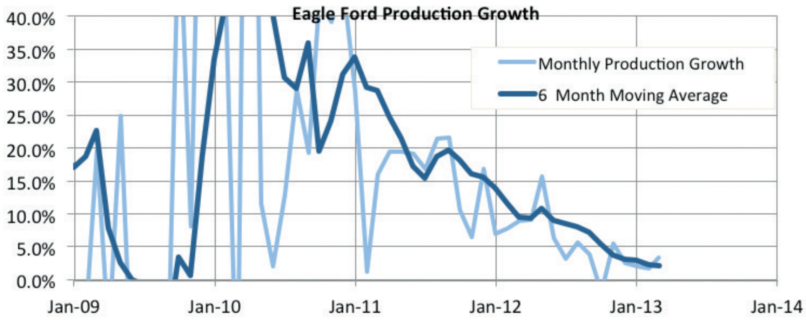


Figure 3c



Plotted on the semi-logarithmic background, where a straight line indicates exponential growth, it is clear that the North Dakota Bakken shows three phases, each starting with a small drop in production rate.

For the first 2¼ years of the high demand during the boom, production rose by about 6% per month. In response to steadily rising oil prices, it then accelerated to nearly 11% per month.

Then, after the drastic price drop in late 2008, the growth rate dropped back to about 4% per month, despite the fairly rapid recovery of oil price. The break in slope occurred at about 100,000 barrels per day, at a time when producers appear to have only just begun to evaluate infrastructure limitations to increasing production.

Overview of Technologies

The shale oil can be extracted by surface and in situ of retorting and depending upon the methods of mining and processing used. As much as one-third or more of this resource might be recoverable.

The amount of oil shale can be economically recovered from a given deposit depends upon many factors, including geothermal heating, mine depth, surface land uses and transport of the oil to the market. There are several technologies which make it possible to produce shale oil within the given economic boundaries and at current market conditions.

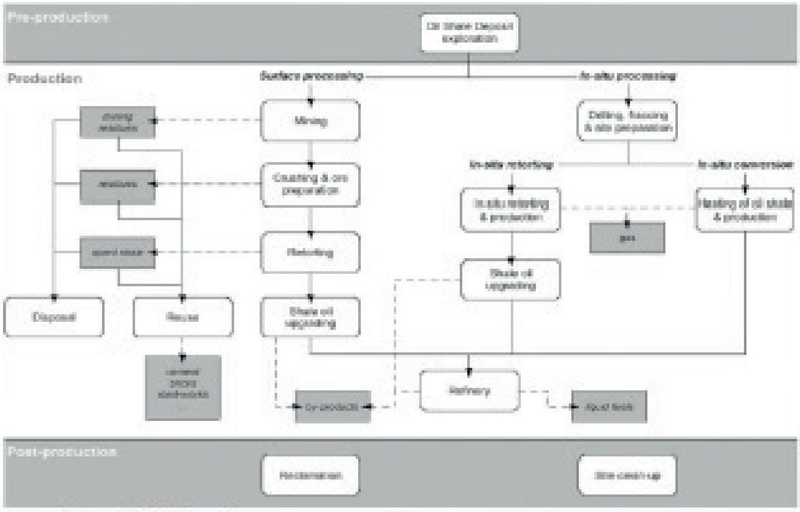
Other applications involve direct firing in special boilers to produce electricity. For example, Estonian companies in Jordan are negotiating purchasing contracts for such boilers, but the relatively high price of electricity production by such installations appears to be an issue. However, there are many other technologies under development (in situ, etc.). Economies of scale are needed to lower unit production costs of these technologies and units would have to become bigger.

Above Ground Extraction

Above ground extraction is the oldest technique of getting the oil shale out of the ground and can be further divided into categories depending on the way heat is applied.

- **Direct Heating**: Air is mixed with the hot shale resulting in combustion. The resultant gases heat the new shale which is being pushed into the retort. The fuel comes out as oil and gas with a very low calorific value British Thermal Unit (BTU).

Figure 4
Technological overview



- **Hot Solids Mixing**: This method involves mixing preheated solids with fresh shale. The heat needed to heat up the solids is generated outside the retort vessel. Because there is no combustion inside the retort, the resulting gas has a very high BTU.

In-situ Retorting (Underground Extraction)
This process involves heating the oil shale underground to extract the oil and other elements. The heating caused by combustion of shale with air leads to the thermal decomposition of Kerogen. The oil is then forced to flow to the production well. In-situ extraction methods can also be classified into different heating methods.

- True In-situ is a method by which the oil and all the other components of oil shale are extracted underground using wells. As soon as the formation is fractured, superheated steam is injected into the formation raising its temperature considerably. When the temperature is high enough for pyrolysis, air is injected into the formation. When the oil shale ignites, the injection well is sealed to increase the pressure in the rock formation.
- Modified In-situ is a relatively new concept to extract oil shale out of the ground. It involves creating an underground fixed-bed retort by blasting and mining. The table below shows the different In-situ methods developed by various companies and advantages and disadvantages of using
- The limited competitiveness of oil shale during the last decades has already forced industry to reduce its cost through improved or innovative technologies and management practices: selective mining and backfilling, in-situ processing, near-zero CO_2 emissions surface retorting and other methods.

At the present time the generators are still the main devices for thermal processing of oil shale in category 25-125 mm. The largest production unit running the process has the capacity of 1000 tonnes of shale per day. It was taken into service in 1980, in Kohtla-Yarve.

The most prospective and high-production in Estonia remain to be the plants with solid heat carrier and capacity on shale 3000 tonnes per day (UTT-3000) which run on «Galoter» (see box with Case Study). Two such plants are operating at Estonian electric power station in city Narva (one of them since 1980, the second one - since 1984).

There is a number of other technologies developed by different companies.

- "Petrosix" developed by the National Brazilian Corporation "Petrobras". This process is used for processing the oil shale from deposit Irati (Brazil). The fractional composition of feed shale is from ¼ to 2¾ inches (6.25-69.0 mm);
- "Lurgi-Ruhrgas" for pyrolysis of oil shale with sizes up to ¼ inch (6.25 mm).
- Retorts of Fushun type for processing the oil shale in China. The fractional composition of oil shale at the entrance in retort constitutes from 8 to 75 mm.
- "Aostra-Tasiyuk" (ATP) developed in Canada by Wiliam Tasiyuk (the company UMATAK Industrial Processes), couldn't be implemented both in Australia and China.
- Chevron is developing an in-situ technology which will be economically sustainable and environmentally responsible.

Production

Currently the oil shale industry is concentrated in a few countries, including Brazil, China, Estonia, Germany, Israel, Russia and the United Kingdom. These countries together used to produce over 30 million tonnes of shale oil per year between 1963 and 1992. From the peak in 1981, the annual production dropped to about 15 million tonnes.

Each country has a specific reason to continue their oil shale activities. In Russia, for example, more than a thousand scientists continue their work on oil shale despite unclear and often negative market signals. However, the strong believe in the future of oil shale helps to retain specialists and recruit followers. There oil shale can be considered a legacy which they want to carry into the future.

Economics

Petroleum-based crude oil is cheaper to produce today than shale oil for several reasons, including the additional costs of mining and extracting. Only a few deposits are currently being exploited: in Brazil, China, Estonia, Germany and Israel.

Production costs of oil from oil shale rock are dependent upon a number of input factors: technology used, properties of oil shale, location of the resource, regulatory and fiscal regimes and final products. On average, the production cost is estimated at between 70 and USUSD100 per barrel. At current crude oil prices (around USUSD95 a barrel sustained price) shale oil can compete with conventional oil.

Country	Proven Resources in Million Barrells
Australia	32,000
Brazil	82,000
China	10,000
Confo (Republic of)	100,000
Estonia	16,000
Italy	73,000
Jordan	34,000
Morocco	53,000
Russian Fedration	248,000
United States of America	4,285,000
Total	**4,933,000**

Environmental considerations

As most industrial processes, production of shale oil faces a number of environmental challenges. In-situ technologies can be harmful to groundwater and other oil shale processing technologies require large amounts of water.

The environmental impacts of above ground retorting are much more technology-specific. For example, technologies using gaseous heat carriers have a problem with solid waste containing organic residue.

Most solid heat carrier technologies struggle with high CO_2 emissions.

Generally, new generation technologies such as fluidized bed combustion, could reduce CO_2 emissions from oil shale-based power plants. Expectations in the 1970's, that the vast resources of oil shale could raise world oil shale production to 150 to 200Mt by 2000, have not materialised. New oil shale processing technologies should be technically feasible, environmentally acceptable and economically viable. Today this still seems to be the main challenge for shale oil's success.

Hydrofracking is used not only to produce gas, but also oil which is actually more profitable. It is expected that US shale oil production will reach 1.4 million barrel/day by 2020. Public concerns include land use, ground water pollution and CO_2 emissions. In the densely populated Europe, these concerns weigh heavily: France and Bulgaria for example outlawed fracking. Resistance grows also in Germany, Romania and Czech Republic. The shale boom is still early in its life span, consequently our understanding of the environmental impact of fracking will become more clear in time.

The economic consequences vary from one country to another. The fracking boom in the US caused oil prices in the US and European markets to drift apart. West Texas Intermediate crude became 13USD/bbl cheaper than Brent. The US shale gas boom depressed natural gas prices by 80 %; now gas in the US costs half of that in Germany.

Generally, the US has witnessed the greatest changes in the gas industry. Amongst these changes are:

- Revival of American manufacturing
- Availability of an extensive pipelines network to transport the product to the market
- Overproduction and benefits to the US consumers

Investors in the US have so far been attracted by the profitability of companies active in the exploitation of shale and sand, and related equipment, either in investing directly in the companies concerned or, indirectly, in energy funds.

However, profitability could become a concern, as a continued decline of shale gas/oil prices would be self-defeating. Due to the lack of exploration, profitability in Europe has not yet been ascertained and would be in any case below US returns.

The main constraint to further expansion of oil shale business will continue to be public concern.

Risks and Rewards in the oil shale business

No investment is risk free. Neither is an investment in oil shale. The highest risks to the developer is the down side price volatility of crude oil. Lest we not forget, oil prices in July of

Technology Case Study - Galoter oil shale technology

Galoter is one of the most efficient technologies in the world for oil shale processing by pyrolysis using the solid heat carrier. The name Galoter is an abbreviation consisting of parts Gal and ter. Gal comes from the name of the technology inventor Galynker Israel Solomonovich – the researcher at the Krzhizhanovsky Power Engineering Institute and ter which refers to the thermal nature of the process. Galynker received the patent with a priority of invention on 29 December 1945. Step by step – at the laboratory of the Institute and at the pilot industrial-scale plants with capacity of 2 / 200 / 500 and 3000 t/day under scientific leadership of ENIN in Estonia, the researchers worked on the development of oil shale thermal processing to solve technical problems and improve the technological process and the equipment. In 1989 the upgraded production units UTT-3000 were put into operation, and they remain until now the largest and most efficient units in the world.

The main competitive advantages of Galoter technology are:

- Thermal processing of oil shale with particle size from 0 to 25 mm;
- Products of the process are the highly calorific shale oil (38-40 MJ/kg) and gas (35-37 MJ/nm3);
- Ash obtained in the oil shale processing under low-temperature combustion of shale semi-coke is used as the solid heat carrier;
- A part of ash not used in the process can be used in construction industry, agriculture and other applications without any environmental limitations;
- The excess heat from combustion products after the technology furnace is used for generation of electricity to run auxiliaries.

New experiments and investigations are currently conducted by ENIN using the modern experimental base. It is estimated that new plants will increase the output of liquid fractions by 150-200% with the same unit capacity unit.

2008 were USD148/bbl; 5 months later, the oil price reached USD30/bbl. Such price volatility impacts investor confidence for years and hinders the formation of the types of capital required to exploit oil shale.

It takes many years for a particular oil shale project to yield financial returns. This problem can be resolved by using financial derivatives such as a forwards contract. The company that extracts the oil from particular oil shale deposit can negotiate a contract with interested refineries that want to purchase that oil in the future and set a specific date and price for delivery (for example USD80/bbl on 13th March 2017).

This way refineries will be obliged to buy oil for that price no matter what the market conditions are. It could very well prove to be a very profitable venture for the purchasing party if the price of crude oil stays above USUSD95/bbl.

Long term derivatives are not very common in the financial industry and if the refineries lack the tools to perform sufficient risk analysis on future and long term price of oil, then this method can only exist in theory.

Regulatory risk

The operating cost of producing oil from oil shale (from a particular deposit) currently does not take into account the carbon or emission tax. It is estimated that the process of extraction oil from oil shale and turning it into feedstock for the refineries, generates 25-75% more emissions than conventional oil, therefore it is reasonably to assume that if an emissions tax was introduced in the US for oil shale then it would one of the biggest factors in the operating costs.

Technological Risk
Since the discovery of oil shale, many companies have spent billions of dollars on research and development to explore different extraction technologies.

Finally, the market players will assess the relevance of different technologies and approaches. They and only they themselves will decide upon their individual needs (imports/exports into/from different countries, marketing purposes, costs etc.).

It is key to remember that costs are the main driver for all economic activities which will include now more and more corporate and social responsibility (CSR), and sustainability aspects. In a cost and CSR-driven economy, the role for voluntary higher standards will remain clearly mitigated

Emerging messages

The world´s transport system is based on one single fuel - oil and today there does not seem to be any realistic alternative to oil. Demand for oil is expected to grow for decades to come, along with the overall demand for energy. Oil shale can help meet this demand and should be regarded as an integral part of the energy mix.

To achieve scaling-up in oil shale production, policies that are consistent, long-term and supported by broad stakeholder participation are needed. They should also fit in the context of larger transportation goals

Supportive government policies have been essential to the development of oil shale over the past decades. Blending regulations, tax incentives, government purchasing policies, and support for infrastructure and technologies have been the most successful in increasing shale oil production. Countries seeking to develop domestic fuel industries will be able to draw important lessons—both positive and negative—from the industry leaders, in particular Russia, Estonia, Jordan, Israel, China, Brazil, the United States, and the European Union.

Oil shale can help diversify supply of fuels, enhance security of supply and mitigate economic volatility related to crude oil price fluctuations.

Support the investment flowing into oil shale business through full transparency of public sector requirements and actions.

Conclusions

Oil shale policies should focus on market development and facilitate sustainable international trade in oil shale and related products. The geographical disparity in production potential and demand pose barriers to trade in oil shale. Free movement of oil-based products around the world should be coupled with social and environmental standards and a credible system to certify the compliance.

Consumer demand is a powerful driver of the market. Therefore, consumer awareness and availability of relevant information have become powerful factors in decision making. Strategies to increase the public's awareness about oil shale should include various forms of public education, such as formal awareness campaigns, public announcements, university research, etc.

When performing analysis of fuel source and type, an LCA is necessary for understanding of economic, energy and environmental impacts using a common, objective and transparent methodology.

3

Natural Gas

Contents

This Chapter is partially based on an updated version of the International Gas Union Strategy Committee report released at the 25th World Gas Conference in Kuala Lumpur in 2012

Strategic insight

1. Summary

In 2012, for the first time in many years, the growth in global gas demand outstripped that of coal. Despite the current economic difficulties, the world might be looking at the 'Golden age of gas', as the global gas market is expected to reach 4 700bcm by 2030. This growth is supported by an increase in gas production potential and expansion of international trade based on a growing number of LNG facilities and high pressure pipelines and will continue for several decades. This average annual growth of 1.4% is slightly higher than anticipated in the IGU commentary provided for the previous edition of the WEC Survey of Energy Resources report published in 2010.

The share of natural gas in primary energy supply is expected to rise from 22% in 2010 to almost 25% in 2030. The total gas market will grow all over the world, but at a different speed in each region or industry. The most significant growth for gas is likely to be in power generation, which could account for 1 900bcm (40%) of the total gas market in 2030. The highest regional growth is expected to take place in Asia driven by the continuing expansion of the Chinese gas market. Proved reserves of natural gas have been identified in every region, with the highest volumes in the Middle East (41%), Europe, including the Russian Federation) (27%) and Asia (15%).

Differences in definitions or coverage can lead to discrepancies: perhaps the most common example in the case of proved gas reserves is the inclusion (intentional or otherwise) of probable reserves in the figures quoted.

On the other hand, as gas reserves are invariably expressed in volumetric terms, they are far less affected by conversion factor differences than oil reserves, for example. Major discrepancies in individual reserve assessments are highlighted below in Country Notes. The discussion of natural gas supply and demand is set in the context of the IGU's regions, which are not identical to the standard WEC geographical regions. However, the differences are essentially marginal and do not invalidate the analysis.

Overall, commercial and regulatory trends suggest that 'gas-on-gas' prices are becoming the dominant global price setting mechanism. Regulated gas prices should increasingly allow a full recovery of costs. However, some form of indexation to oil or oil products will remain of fundamental importance in many parts of the world.

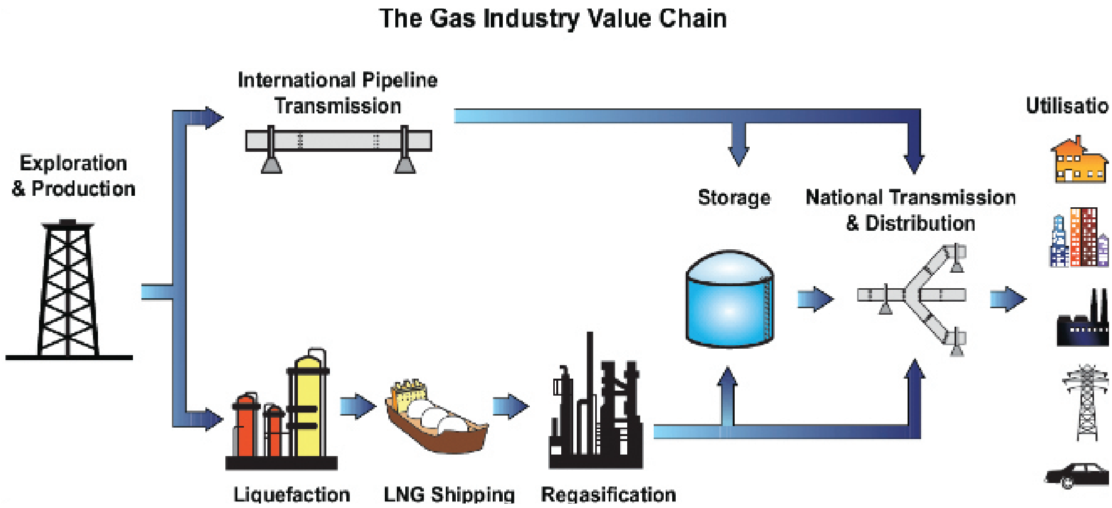
2. Technical and economic considerations

Natural Gas is a mixture of hydrocarbons, of which by far the largest component is the simplest hydrocarbon, methane ($CH4$). Methane is an odourless, colourless, non-toxic gas which is lighter than air.

Most of the natural gas that has been discovered so far was almost certainly formed by biogenic processes similar to those that created oil. Over millions of years the residues of decomposed

Figure 1

Source: IGU



organic material exposed to intense pressure and high temperatures have become hydrocarbon minerals, including natural gas. These hydrocarbon minerals can be found both in the original source rock where they were formed (including shale formations) and also in more porous reservoir rocks that are the conventional oil and gas fields. Natural gas also includes some heavier hydrocarbons such as methane (C2H6), propane (C3H8), butane (C4H10), and there can be a wide range of different non-hydrocarbon gases that also occur in the mixture in the reservoir rocks.

Gas value chain

Figure 1 illustrates, in a simplified form, the main components of the gas value chain.

Whilst synthetic natural gas and bio-gas are important components that are increasingly being integrated into the gas chain, the global gas industry, based on conventional and unconventional gas still provides more than 99% of global gas supplies.

The distribution of natural gas around the world is more diverse than oil, but nevertheless a large proportion of natural gas needs to be transported from the producing countries and regions (for example, Norway, Russia, Qatar, the Caspian area and North Africa) to the consuming countries and regions (e.g. Japan, China and Europe) with insufficient domestic and regional indigenous gas supplies. International high pressure pipelines provide direct and reliable links from producers to consumers.

These outstanding engineering achievements remain the main routes for transportation of vast international flows of gas. For example, a recently completed pipeline project Nordstream, Phase 2 (inaugurated in October 2012) which directly connects Russia to Germany via the Baltic Sea over 1200 kilometres is the world's longest underwater natural gas pipeline. At the end of 2012, construction began on the SouthStream project to bring gas from Russia across the Black Sea to Bulgaria and further to Italy and Austria.

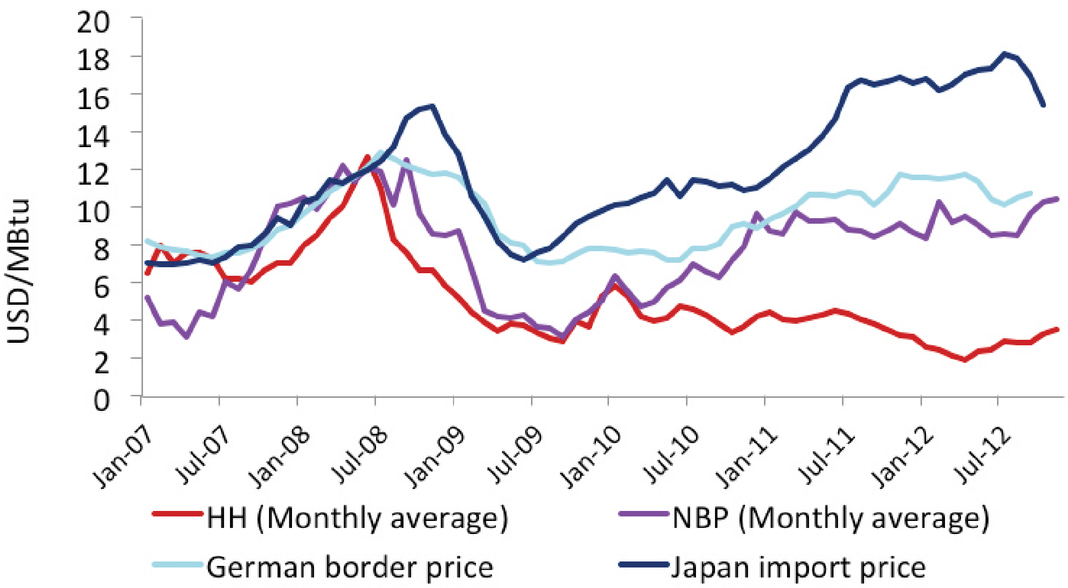
Exploration, production and processing

The offshore gas production in North-West Europe is a good illustration of the three different types of natural gas production that we can broadly categorise by the type of reservoir.

Figure 2

Gas prices have risen, fallen and diverged

Source: updated from IEA 2012 Medium Term Outlook



- 'Dry gas fields' requiring very little processing of the reservoir fluids needed to achieve pipeline quality gas - typical in the Southern North Sea
- 'Condensate gas fields' in which the heavier natural gas hydrocarbons can be separated as natural gas liquids (NGLs) – typical in the Central North Sea
- Oil fields with 'associated gas', sometimes with a natural gas cap that can be produced separately and even temporarily re-injected to enhance oil production – typical in the Northern North Sea.

Once produced natural gas will need some processing. If it is dry gas with very few impurities, then it might be sufficient to check the gas quality and make sure that it is adjusted to the correct pressure and temperature for the next stage of its journey. More likely, however, that it will also be necessary to treat "wet" gas that has come from the upstream reservoir to deal with one or more components that need to be removed to meet the gas quality requirements for onward transportation.

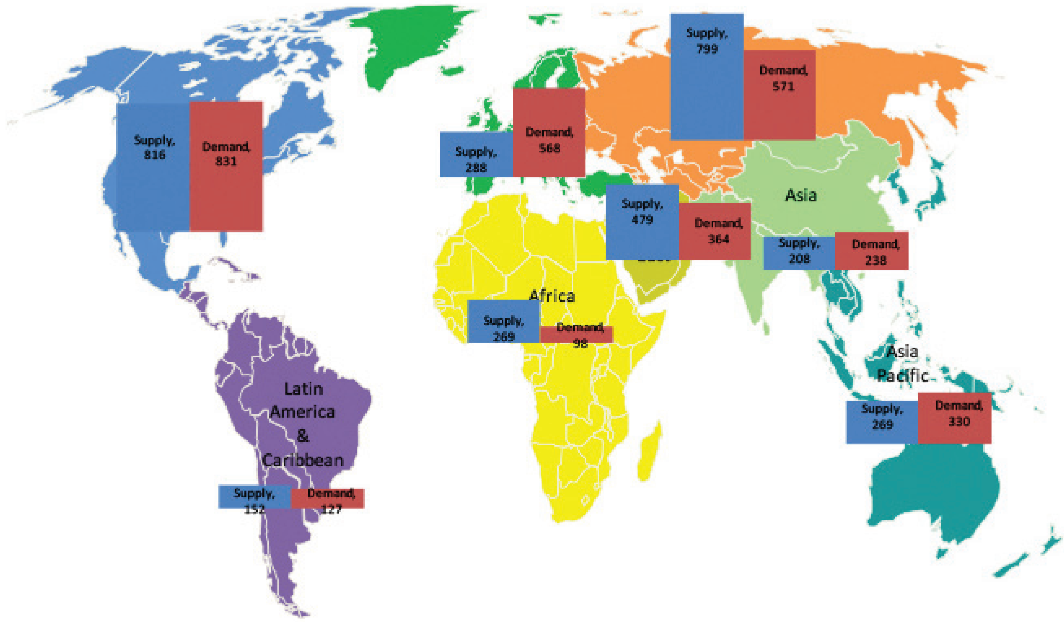
International and National High-Pressure Pipelines

International high pressure pipelines provide direct and reliable links from producers to consumers. These immense achievements of engineering remain the main way for vast international flows of gas. One recently completed project is the Nordstream phase 2 (inaugurated in October 2012) which connects Russia directly to Germany via the Baltic Sea.

Given its length of 1 200 kilometres it is the world's longest underwater natural gas pipeline. Before the end of 2012, construction began on the SouthStream project to bring gas from Russia across the Black Sea to Bulgaria and onwards to Italy and Austria.

Generally, even larger investments in gas transmission pipelines are taking place in individual countries, particularly in the USA and in China. The shale gas revolution in North America changed indigenous supply patterns and led to many new onshore pipeline projects to enable higher levels of gas production to be brought to market. In the US, however, several

Figure 3
Analysis is based on the eight IGU regions
Source: IGU



of the main shale gas formations are relatively well located, either close to the final market or within the economic reach of existing infrastructure. In contrast, the geographical challenge to deliver indigenous natural gas to the main consuming areas has been far more demanding in China. The final length of the second West-East Pipeline linking gas production in the west to consuming areas in the east was over 8 700 kilometres, including both east and west sections and eight branches, making it probably the world's longest natural gas pipeline. Construction of a third West-East Pipeline of similar proportions was already well under way by the end of 2012 as demand for natural gas in China continues to grow rapidly.

Liquefaction, LNG shipping and regasification

Gas liquefaction, to make natural gas easier to transport by ship (or occasionally by road in tankers) to the market where it is then regasified, has become almost as important as pipelines as a means of international delivery of natural gas. Liquefaction involves pre-treatment to purify the natural gas from pollutants like H_2S or CO_2, remove any traces of heavy metals and control the moisture level. The processed natural gas is then refrigerated to a temperature of approximately minus 161 degrees Celsius. This refrigeration process involves compression, condensation and expansion of refrigerants that exchange heat with natural gas until it becomes a liquefied natural gas (LNG) with one 1/600th of the original volume.

A large LNG fleet of ships (or road tankers) is essential to prevent bottlenecks developing in the supply chain. Since January 1959 when the Methane Pioneer set off for Europe with its modest cargo of liquefied natural gas from the Louisiana Gulf coast of the USA, international LNG trade has developed a global fleet that now amounts to over 350 active ships, the largest carrying up to 266,000 m3 of LNG. Annual worldwide deliveries are equivalent to more than 300 bcm of natural gas i.e. about 10% of global consumption.

Some countries like Japan and Korea have long been reliant on LNG and have based their successful downstream markets on a range of LNG suppliers. The growth of international gas trade also means that many more countries now have LNG reception terminals and there is a flourishing market in LNG deliveries and diversions to the markets with highest value. This flexibility is of course only possible when there are sufficient ships available (a diversion may well result in a longer route) and sufficient capacity in the re-gasification terminals to where a ship might be diverted. The capacity in the re-gasification terminal comprises not only the delivery slot to enable the ship to be unloaded, but also short-term storage of the unloaded LNG and re-gasification (in which LNG is warmed up) before compressing the natural gas into a national or local transmission pipeline.

Storage

The ability to liquefy natural gas means that it can be stored and made available at very high delivery rates, but the process of liquefaction and storing LNG is potentially very expensive.

In many parts of the world gas demand is seasonal and the storage of very large volumes of gas that are needed (for example, for residential space heating in northern hemisphere in winter) is best achieved underground in natural geological formations, particularly if suitable structures can be found near the local pipeline grid that serves the centres of gas demand. One advantage of storing gas in a structure that used to be an oil or gas reservoir is that its natural integrity has been proven for containing reservoir fluids at high pressures.

Another form of underground storage (UGS), that offers potentially higher delivery rates albeit sustainable perhaps over a number of weeks rather than throughout the winter months, is salt cavities. Here, the storage cavities of the optimum shape and size are leached out from the underground salt formation. In all forms of UGS an important component of the storage facility is the 'cushion' gas that remains in the store so that a reasonable withdrawal rate can be achieved. The 'working gas' in the store is injected (compressed) into the UGS on top of the cushion gas and it is this working volume that is taken out for the heating season or for other commercial reasons during the storage cycle.

Local transmission and distribution

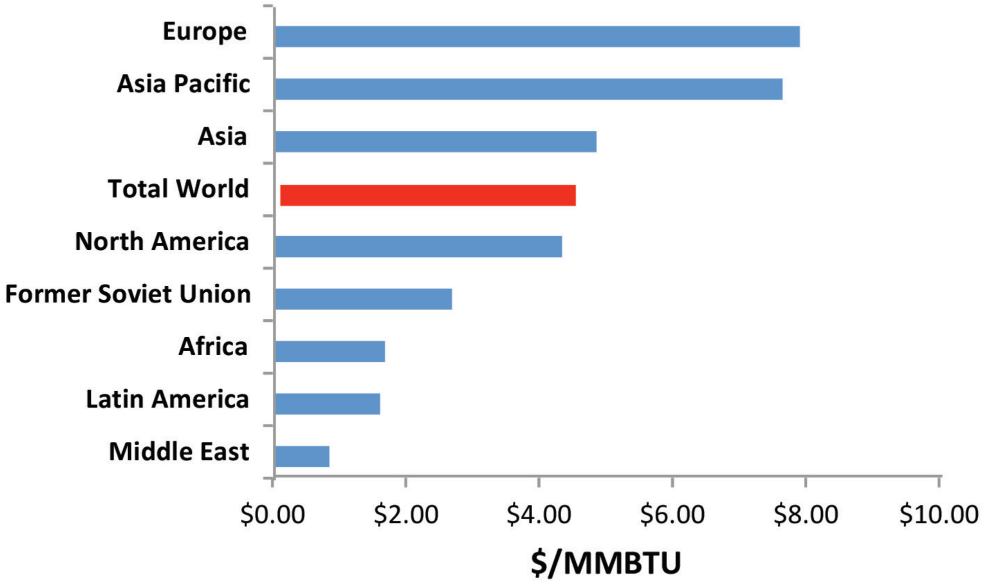
The gas in the transmission system is at high pressure (typically 50-80 bar) and, depending on the final use, may pass through a series of pressure reductions, metering and quality checks leading to low pressure distribution pipeline systems with their own pressure and flow controls and final metering at the supply point of the end consumer. Technology is enabling gas operations and gas markets to develop in ways that should lead to further efficiency improvements in grid operation and utilisation. Smart grid technology as well as smart metering still have a long way to go but have already demonstrated significant fuel savings through grid optimisation at Transmission level.

Utilisation

The economic availability of natural gas combined with its qualities of efficiency, quality, reliability, convenience and responsiveness to the consumers' needs make it an ideal choice for a wide range of uses in many parts of the world.

Industrial gas demand requires a more competitive offering in relation to other fuels, but the proven high efficiency appliances that already exist for natural gas could be a springboard for further growth despite some global economic uncertainty in the manufacturing sector.

Figure 4:
Average wholesale price in each IGU region in 2010
Source: IGU



Natural gas is also a widely used feedstock for the petrochemical industry, and this use is being further developed by some natural gas producing nations as an alternative to exporting LNG or constructing new international pipelines.

Whilst today still at a relatively low level, the use of natural gas as a transport fuel is possibly the most rapidly growing gas use across the world,. There are encouraging signs both onshore, with compressed natural gas (CNG) fuelling millions more cars, trucks, busses and lorries, and offshore with LNG-fuelled ships being favoured over more polluting rivals in environmentally sensitive areas.

Overall, however, the use of natural gas for power generation remains the largest and most important growth sector. How much and how fast the global gas market will grow depends on fundamental economics, which in turn are influenced by politics related to energy and to climate change.

Advances in gas technology.

Wider application of the latest natural gas technologies is delivering benefits along the whole gas chain:

- In exploration, production and the treatment of natural gas, there are ongoing technological improvements and cost reductions for shale gas exploitation, and enhanced gas production through applications of fracking technology in ‘conventional’ low permeability reservoirs.
- Longer and higher pressure transmission pipelines are allowing greater economies of scale in the delivery of gas from remote sources of supply to consuming markets.
- New forms of LNG facilities, including (FLNG) Floating LNG are opening up new markets and expanding the possibilities for gas supply diversity in established markets.
- Distribution systems continue to be upgraded and efficiency gains made through the application of smart grid and smart meter technologies.

Figure 5
Wholesale gas is increasingly priced on the basis of traded gas hubs
Source: IGU

- Replacement of boilers and other appliances with the latest high-efficiency designs is making the use of gas even more economically and environmentally attractive.

Wholesale gas prices vary throughout the world

In 2010, for example, the average regional gas prices varied throughout the world as shown in figure 4 above. Despite the averaging effects that dampen the results over each region, there is still a factor of ten between the regions with lowest wholesale gas prices and the regions with the highest.

The tension that results from such diverse wholesale gas prices across the globe leads to enhanced international trade (to exploit the arbitrage opportunities) and it also leads to pressure to change wholesale gas price formation mechanisms. In particular, customers and retail suppliers in competitive markets are compelled to align their gas costs with the traded market. This effect has led to a trend of wholesale gas prices being linked increasingly to traded natural gas prices as summarised in Figure 5 (overleaf).

There is, however, considerable uncertainty about future gas price formation mechanisms and the extent to which global gas price differences will persist. The overall trend that we have seen since 2005 suggests, however, that 'gas-on-gas' price formation will be the dominant global mechanism well before 2030, that regulated gas prices will increasingly allow recovery of full cost (provided these are economically incurred) and that some form of indexation to oil or oil products will still be of fundamental importance in parts of the world where the local gas markets is not open to competition or trading in natural gas is not sufficiently liquid.

Global perspectives of regional gas demand

An ever increasing world population and expected GDP growth in major developing countries have a huge impact on energy consumption and more specifically an impact both on gas demand and gas supply. Environmental issues and also technical developments like advances in shale gas production and cost reduction of renewable energy sources are playing a main role in the future fuel mix. Analysing the main trends in natural gas demand and supply against a background of political and economic uncertainty is therefore a challenging job.

IGU Strategy Committee experts performed both a local 'bottom-up' analysis and a top-down consistency check to establish regional expectations of indigenous supply and indigenous demand. This IGU Expert View then results in a Reference Scenario in which each of the eight IGU regions ether have some additional export potential, or may exhibit a supply shortfall that will need to be satisfied by imports from another region

To frame gas supply into a wider energy context, an assessment was made of the development of total primary energy consumption (PEC) in each of the eight IGU regions and the sectors within those regions.

Primary energy demand is expected to increase with an average annual growth of 1.3% from 2010 to 2030. The gas share of primary energy demand would rise from 22% in 2010 to almost 25% in 2030. Whilst the relative share of natural gas is quite different in each region, the share of gas in primary energy demand is expected to grow in all regions, except for the giant North America and CIS markets where the share stays relatively stable. Short-term economic trends, however, have squeezed the gas market in some regions, not least in Europe, where low priced coal, displaced by the shale gas revolution in North America, has undercut gas-fired power generation.

Natural Gas Demand by Region – IGU Expert View (Reference Scenario)

Natural Gas demand is projected to increase by 1.4% per year between 2010 and 2030 to a total of 4.7 tcm. Despite the effects of the recent global economic downturn, when compared with the IGU report of 2009, this new projection is about 300 bcm higher by the year 2030. The increase is spread across the globe, and includes the major production and consumption regions of North America, CIS as well as some increase in Europe. The most dynamic regions in terms of percentage growth are Asia (driven by China), Africa and the Middle-East.

Natural gas demand by market sector – IGU Expert View (Reference Scenario)

In the residential and commercial sector a moderate growth is expected from 0.7 tcm now to well over 0.9 tcm in 2030. The most significant rise is foreseen in Asia, mainly driven by the increased number of homes connected to the gas supply grid.

Gas demand in industry is expected to grow from 800 bcm in 2010 to 1200 bcm in 2030 driven in a large part by developments in the Chinese and Indian economies. Overall future industrial gas demand is somewhat lower than in the 2010 WEC report as industrial output is more constrained in OECD countries whilst on average better energy efficiency is achieved globally.

The increase of total global gas demand in the past two decades was driven, above all, by the need for clean, efficient and competitively priced power generation.

With billions of people needing electricity supplies, this sector is set for continuing growth in the coming decades. The way gas is priced, however, can present some difficult challenges to the economics of power generation projects. In particular, if, as hoped by some producing countries, there were a return to some form of 'oil-parity' in Europe or a full continuation of oil indexation in Asia, then that would reduce the demand for gas-fired power generation below the expectations shown below.

Furthermore, if the gas price for power generation were held unduly low in North Africa and the Middle East, then that would reduce the likelihood of approval for investment in major renewable energy projects and may prevent their successful implementation. This would make global climate change goals more difficult to achieve despite the increased use of natural gas. -

Overall, the global power sector is expected to grow to almost 1600 bcm in 2020 and around 1900 bcm in 2030. The final result in terms of natural gas consumption in the power sector, however, is extremely dependent on the policies concerning renewable energy, which in turn are subject to economic and social pressures.

With a total projected volume of 1900 bcm in 2030, the prospects for gas for power generation are impressive. However, at the same time a lot of uncertainties arise. How will renewable energy sources develop and will they take over part of the electricity market? What will be the influence of CO_2? A correctly implemented emission-trading scheme for CO_2 costs or taxes based on the CO_2 content would benefit natural gas in relation to other fossil fuels. Uncertainty in the price of CO_2, however, creates an additional risk for investment. What will be the impact of CCS plants (Carbon Capture and Storage) on gas demand in the power sector?

The expected gas demand is large, but is also very uncertain when considered against the background of these complex issues.

Gas consumption in the transport sector (mainly Natural Gas Vehicles- NGVs) is expected to become more important, growing from around 90 bcm now to 150 bcm in 2030. Main users are CIS, Middle-East and Asia.

Global and regional natural resource analysis - Gas production and supply

In parallel with the analysis of future gas demand summarised above, our experts studied the available information on gas reserves and projects to establish expected regional supply levels. It is well known that natural gas reserves are abundant to cover the global gas demand for many decades, and the inclusion of some unconventional gas in the reserve base has clearly enhanced economically recoverable reserves in the last few years. Moreover, technological developments and higher energy prices in some regions have increased the economic reserves locally as well as the diversification of sources and routes to bring these reserves to market.

The current developments on unconventional gas, especially shale gas in the United States, are spectacular and have led to upward revisions for the prospects in North America. The potential for unconventional gas in some other regions is also significant. At several places around the globe, like Poland and China, the opportunities for shale gas are being actively investigated.

Regional gas supply potential

For all the regions, the expected gas supplies were not forced to balance with gas demand. The difference between demand and supply indicates possible over or under supply for that region, and hence the likely need for imports or the possibility of export potential.

Overall, increased production will enable world gas supplies (in terms 'pipeline quality' gas) increase to over 4.8 tcm by 2030, with the CIS (dominated by Russia) consolidating its position as the region with largest gas production.

The natural gas supply outlook for **North America** has changed significantly over the last five years. The key change is the economic development and production from natural gas bearing shale resources and the global implications that this has had. Total North American gas production is projected to increase from 810 bcm in 2010 to almost 1000 bcm by 2030. The share of unconventional gas in the US will grow from 60% to over 73% by 2030.

In **Latin America**, natural gas production both onshore and offshore is expected to grow from 150 bcm now to 250 bcm in 2030.

In **Europe**, indigenous resources currently satisfy about half of the gas demand. The largest European producers are Norway (105 bcm), the Netherlands (88 bcm) and the UK (60 bcm). In the period from 2010 to 2030, most of this production will decline with only Norway expected to maintain its production level. Several geological plays in Europe are being explored for "unconventional gas", mainly shale gas reserves. However, this development is currently at an early stage and the economics do not match up with new imports if these are available at competitive (gas hub) prices. The result is that no significant indigenous unconventional gas is included in the European region.

Gas production in **Africa** is expected to more than double between now and 2030, growing to 400 bcm/year, with Algeria and Nigeria as the main suppliers. Half of the production could be exported to other regions, enabling Africa potentially to benefit from international prices whilst contributing significantly to diversification in global gas supply.

The **Middle East** is endowed with a wealth of gas resources, but capital investments remain the main concern due to geopolitical issues and higher capital costs. The largest gas producing countries are, and will remain by far, Iran and Qatar, followed by Saudi Arabia. Iraq holds promising resources and could become a significant gas producer (and exporter). The Middle East total gas production is expected to increase from 480 bcm in 2010 to 840 bcm in 2030. In 2030, around 200 bcm will be exported mainly to Europe and Asia.

In the **CIS**, Turkmenistan, Kazakhstan, Uzbekistan, and Azerbaijan together with **Russia** are the main gas producing countries and should remain in this position in 2030. Together, Russia and the CIS countries account for around 25% of the world's total gas production. Gas production in the region is expected to increase by 45% from 2010 to 2030 when it should reach 1150 bcm.

In **Asia**, gas production has more than doubled in the last decade up to around 210 bcm and the question is whether or not this astounding increase could occur again? Despite substantial proven and potential gas reserves, Asian natural gas production is not keeping pace with demand. Over the next 20 years, IGU experts expect production to reach 460 bcm, but the gap between supply and demand will increase almost seven-fold.

The key challenges to increase gas production are the development of adequate transport infrastructure as new resources are far away from markets, in particular for China and India, and relatively low prices are a constraint in some countries. Additionally, the development of unconventional gas requires appropriate expertise to be developed or acquired. From a regional point of view, China appears as the leading country. By 2011, China was already a relatively large producer – it produced more than Saudi Arabia, and most of its production is conventional gas. IGU forecasts assume a strong growth in China, where production reaches 250 bcm by 2030 and the successful development of both CBM and in a later stage, shale gas. In India gas production will increase markedly reaching around 100 bcm by 2035.

Production in Asia Pacific will grow substantially to 570 bcm in 2030. The region includes big LNG exporters, Indonesia, Malaysia, Australia and Brunei accounting for about 33% of the total world LNG production, but the picture is increasingly complex, with intra-regional trade increasing and Australia becoming a major gas producer and LNG exporter in Asia Pacific as well as a potential global rival to Qatar.

The changing global gas balance

If natural gas demand is increasing from 3130 bcm in 2010 to 4700 bcm in 2030, will there be sufficient gas supply to satisfy this growth? At a global level, the answer is yes. The following figure (Figure 6 overleaf) plots global gas demand and gas supply up to 2030, suggesting that if the projects went ahead and supplies could reach the markets, then there would be a healthy gas supply surplus through to 2030.

Gasification and production projects can of course be delayed or occasionally advanced, and we all know that the economic cycle can give us a bumpy ride, but there is a clear message that natural gas has a global potential for sustained growth during the coming decades. Whilst in practice there may well be periods when it is more a buyers' or sellers' market, we have a clear expectation that supply can continue to satisfy demand in the long run. But, this is predicated on growing international and indeed inter-regional trade.

Inter-regional gas trade

Our global natural gas balance is the outcome of the different regional analyses. In terms of net importers, three regions stand out:

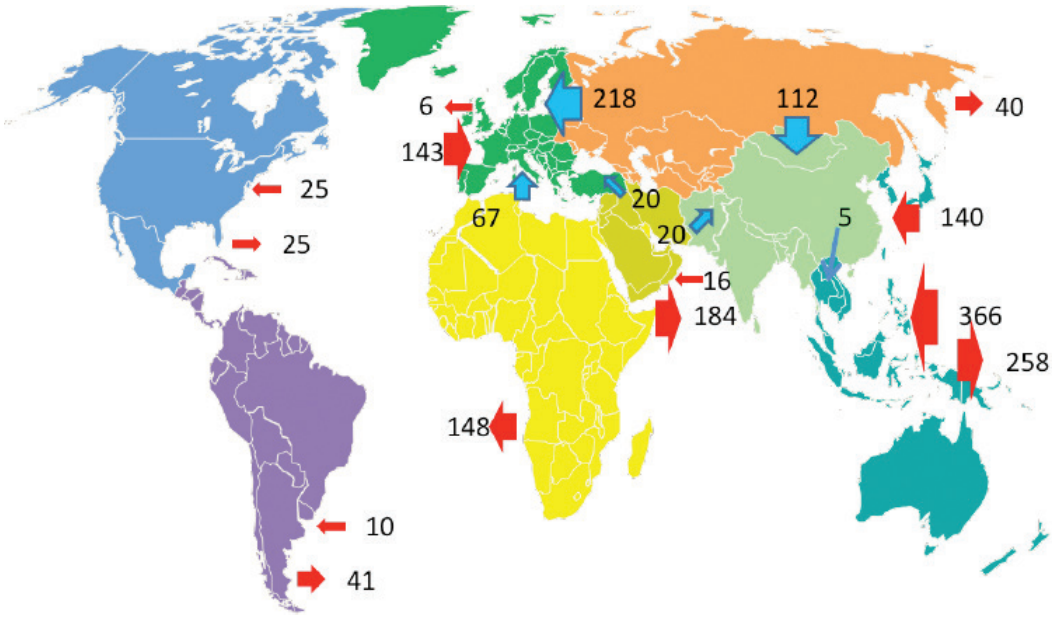
Europe is, and will remain, by far the largest net importer; European net imports could exceed 440 bcm by 2030, a 58% increase compared to 2010 levels. Europe exports only small amounts of LNG from Snøvhit in Norway.

Continental **Asia** is set to become the second largest importing region by 2030, driven by the growing energy requirements of China and India. Imports are multiplied eightfold, with around 270 bcm needed by 2030, compared to around 30 bcm in 2010. We can envisage some exports by pipeline from Myanmar to Asia Pacific.

In third position in terms of imports stands **Asia Pacific**. This diverse area will continue to be a net importer, but the rapidly increasing demand in Japan, Korea and the South-East Asian region is partially compensated by the surge in Australian LNG exports. Net imports will almost double to around 80 bcm by 2030.

Whilst the USA will establish and retain some LNG export potential, the **North American** region remains internally balanced. **Latin America and Caribbean** will export around 30 bcm of LNG. In terms of direct trade, the whole of the Americas will remain only physically linked to the rest of the global gas market through LNG imports and exports.

Figure 6
Global LNG and Inter-regional Pipeline Imports and Exports in 2030 (bcm)
Source: IGU



Africa and the **Middle East** have a similar growth in terms of exports, reaching close to 200 bcm of net exports by 2030. The largest exporter remains the CIS region, with a doubling of its gas exports compared to 2010 reaching 370 bcm. These three regions export both LNG and pipeline gas, but only Africa and CIS do not import any gas from the other regions, while the Middle East may continue to remain an LNG importer.

LNG Trade

Global LNG trade is expected to more than double over the coming 20 years, increasing from 300 bcm in 2010 to 660 bcm by 2030. This requires a rapid build-up of liquefaction capacity around the world. There was already a first wave of new LNG capacity that arrived over 2009-11 with over 100 bcm of new LNG capacity coming on line, notably 63 bcm of LNG capacity from Qatar. The next wave will be coming mostly from Australia, Papua New Guinea and Indonesia with some 95 bcm of LNG export capacity having reached FID and expected to start over 2012-17.

North American LNG exports are part of the IGU scenario, but never in very high volumes. Indeed, on a regional basis, the annual supply and demand are very much balanced, and the region continues to import some LNG (Mexico, Quebec) at the same time as it exports LNG (Western Canada, United States). The US LNG terminals may well also have a seasonal role; exporting when prices are sufficiently high in other parts of the world, but importing when the local gas supply/demand is tight and Henry Hub prices are high.

On the import side, **Asia Pacific** remains by far the largest LNG importer, representing around half of total LNG imports by 2030. Europe and Continental Asia follow but the two regions' combined LNG imports are still below that of Asia Pacific (around 140 bcm by 2030). Three other regions also import LNG, but in smaller quantities (below 20 bcm): North America, Latin America and the Middle East.

Overall Regional import/export balances

The figure above summarises the expected developments in global inter-regional gas trade in 2030. Only the main pipeline routes between IGU regions are shown. There are also many international trade routes within each region, for example by high pressure pipeline from Canada to USA, which are not included on this map. There are also ideas for other inter-regional links that we have not included; several of these may well go ahead if favourable economic and political conditions were to prevail.

There is, however, considerable uncertainty about future gas price formation mechanisms and the extent to which global gas price differences will persist. The overall trend that we have seen since 2005 suggests, however, that 'gas-on-gas' price formation will be the dominant global mechanism well before 2030, that regulated gas prices will increasingly allow recovery of full cost (provided these are economically incurred) and that some form of indexation to oil or oil products will still be of fundamental importance in parts of the world where the local gas markets is not open to competition or trading in natural gas is not sufficiently liquid. An ever increasing world population and expected GDP growth in major developing countries have a huge impact on energy consumption and more specifically an impact both on gas demand and gas supply. Environmental issues and also technical developments like advances in shale gas production and cost reduction of renewable energy sources are playing a main role in the future fuel mix. Analysing the main trends in natural gas demand and supply against a background of political and economic uncertainty is therefore a challenging job.

Global perspectives of regional gas demand

IGU Strategy Committee experts performed both a local 'bottom-up' analysis and a top-down consistency check to establish regional expectations of indigenous supply and indigenous demand. This IGU Expert View then results in a Reference Scenario in which each of the eight IGU regions ether have some additional export potential, or may exhibit a supply shortfall that will need to be satisfied by imports from another region

To frame gas supply into a wider energy context, an assessment was made of the development of total primary energy consumption (PEC) in each of the eight IGU regions and the sectors within those regions.

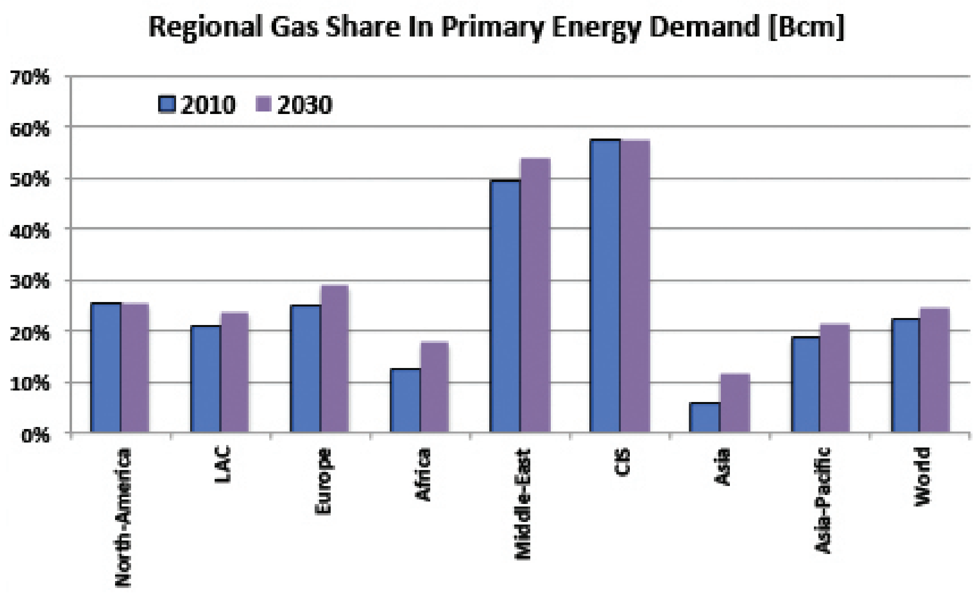
Primary energy demand is expected to increase with an average annual growth of 1.3% from 2010 to 2030. The gas share of primary energy demand would rise from 22% in 2010 to almost 25% in 2030. Whilst the relative share of natural gas is quite different in each region. the share of gas in primary energy demand is expected to grow in all regions, except for the giant North America and CIS markets where the share stays relatively stable. Short-term economic trends, however, have squeezed the gas market in some regions, not least in Europe, where low priced coal, displaced by the shale gas revolution in North America, has undercut gas-fired power generation.

With a total projected volume of 1900 bcm in 2030, the prospects for gas for power generation are impressive. However, at the same time a lot of uncertainties arise. How will renewable energy sources develop and will they take over part of the electricity market? What will be the influence of CO_2? A correctly implemented emission-trading scheme for CO_2 costs or taxes based on the CO_2 content would benefit natural gas in relation to other fossil fuels. Uncertainty in the price of CO_2, however, creates an additional risk for investment. What will be the impact of CCS plants (Carbon Capture and Storage) on gas demand in the power sector?

Figure 7

Changing regional gas share of primary energy – IGU Expert View

Source: IGU



The expected gas demand is large, but is also very uncertain when considered against the background of these complex issues.

Gas consumption in the transport sector (mainly Natural Gas Vehicles- NGVs) is expected to become more important, growing from around 90 bcm now to 150 bcm in 2030. Main users are CIS, Middle-East and Asia.

In parallel with the analysis of future gas demand summarised in the above pages, our experts studied the available information on gas reserves and projects to establish expected regional supply levels. It is well known that natural gas reserves are sufficiently abundant to cover the global gas demand for many decades, and the inclusion of some unconventional gas in the reserve base has clearly enhanced economically recoverable reserves in the last few years. Moreover, technological developments and higher energy prices in some regions have increased the economic reserves locally as well as the diversification of sources and routes to bring these reserves to market

The current developments on unconventional gas, especially shale gas in the United States, are spectacular and have led to upward revisions for the prospects in North America. The potential for unconventional gas in some other regions is also significant. At several places around the globe, like Poland and China, the opportunities for shale gas are being actively investigated.

For all the regions, the expected gas supplies were not forced to balance with gas demand. The difference between demand and supply indicates possible over or under supply for that region, and hence the likely need for imports or the possibility of export potential.

Overall, increased production will enable world gas supplies (in terms 'pipeline quality' gas) increase to over 4.8 tcm by 2030, with the CIS (dominated by Russia) consolidating its position as the region with largest gas production.

Figure 8
World - Natural Gas Demand by Region – IGU Expert View
Source: IGU

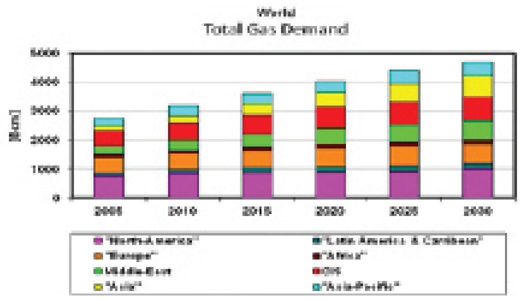
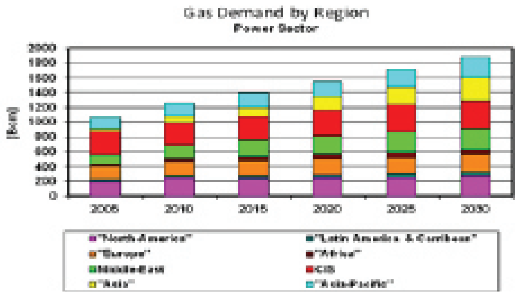


Figure 9
Gas-fired power sector to 2030 – IGU Expert View
Source: IGU



The natural gas supply outlook for North America has changed significantly over the last five years. The key change is the economic development and production from natural gas bearing shale resources and the global implications that this has had. Total North American gas production is projected to increase from 810 bcm in 2010 to almost 1000 bcm by 2030. The share of unconventional gas in the US will grow from 60% to over 73% by 2030.

In **Latin America**, natural gas production both onshore and offshore is expected to grow from 150 bcm now to 250 bcm in 2030.

In **Europe**, indigenous resources currently satisfy about half of the gas demand. The largest European producers are Norway (105 bcm), the Netherlands (88 bcm) and the UK (60 bcm). In the period from 2010 to 2030, most of this production will decline with only Norway expected to maintain its production level. Several geological plays in Europe are being explored for “unconventional gas”, mainly shale gas reserves. However, this development is currently at an early stage and the economics do not match up with new imports if these are available at competitive (gas hub) prices. The result is that no significant indigenous unconventional gas is included in the European regional supply forecast.

Gas production in **Africa** is expected to more than double between now and 2030, growing to 400 bcm/year, with Algeria and Nigeria as the main suppliers. Half of the production could be exported to other regions, enabling Africa potentially to benefit from international prices whilst contributing significantly to diversification in global gas supply.

The **Middle East** is endowed with a wealth of gas resources, but capital investments remain the main concern due to geopolitical issues and higher capital costs. The largest gas producing countries are, and will remain by far, Iran and Qatar, followed by Saudi Arabia. Iraq holds promising resources and could become a significant gas producer (and exporter). The Middle East total gas production is expected to increase from 480 bcm in 2010 to 840 bcm in 2030. In 2030, around 200 bcm will be exported mainly to Europe and Asia.

In the **CIS**, Turkmenistan, Kazakhstan, Uzbekistan, and Azerbaijan together with **Russia** are the main gas producing countries and should remain in this position in 2030. Together, Russia and the CIS countries account for around 25% of the world’s total gas production. Gas production in the region is expected to increase by 45% from 2010 to 2030 when it should reach 1150 bcm.

In **Asia**, gas production has more than doubled in the last decade up to around 210 bcm and the question is whether or not this astounding increase could occur again? Despite substantial proven and potential gas reserves, Asian natural gas production is not keeping pace

Figure 10
Proven gas reserves in the eight IGU regions

Source: IGU

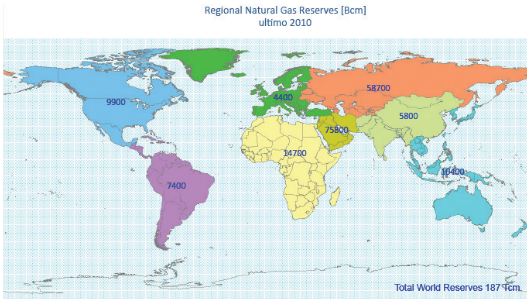


Figure 11
Regional gas production to 2030

Source: IGU

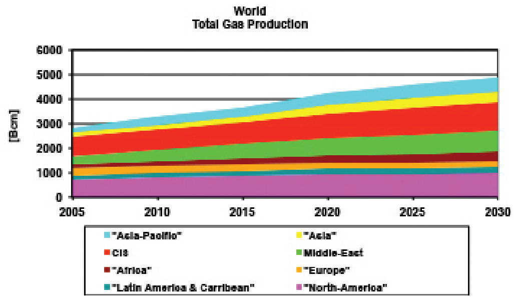
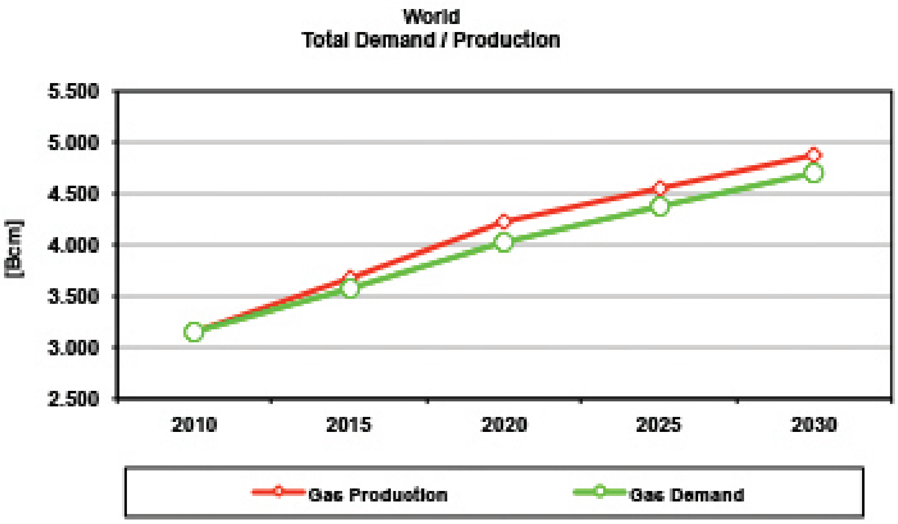


Figure 12
The global gas supply and demand balance – IGU expert view

Source: IGU

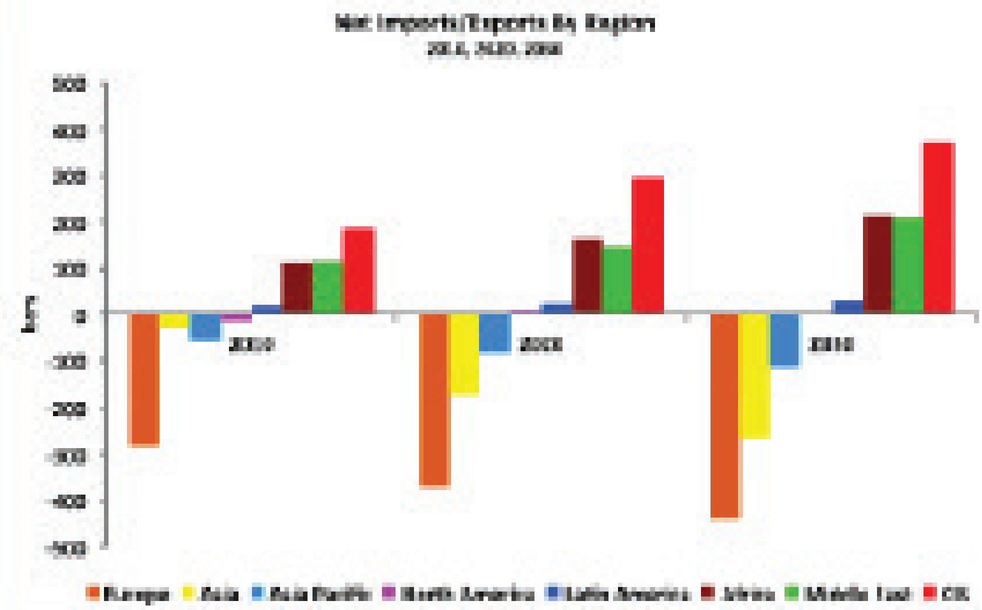


with demand. Over the next 20 years, IGU experts expect production to reach 460 bcm, but the gap between supply and demand will increase almost seven-fold.

The key challenges to increase gas production are the development of adequate transport infrastructure as new resources are far away from markets, in particular for China and India, and relatively low prices are a constraint in some countries. Additionally, the development of unconventional gas requires appropriate expertise to be developed or acquired. From a regional point of view, China appears as the leading country. By 2011, China was already a relatively large producer – it produced more than Saudi Arabia, and most of its production is conventional gas. IGU forecasts assume a strong growth in China, where production reaches 250 bcm by 2030 and the successful development of both CBM and in a later stage, shale gas. In India gas production will increase markedly reaching around 100 bcm by 2035.

Production in **Asia Pacific** will grow substantially to 570 bcm in 2030. The region includes big LNG exporters, Indonesia, Malaysia, Australia and Brunei accounting for about 33% of the total world LNG production, but the picture is increasingly complex, with intra-regional trade increasing and Australia becoming a major gas producer and LNG exporter in Asia Pacific as well as a potential global rival to Qatar.

Figure 13
Changing imports and exports by region
Source: IGU



The changing global gas balance

If natural gas demand is increasing from 3130 bcm in 2010 to 4700 bcm in 2030, will there be sufficient gas supply to satisfy this growth? At a global level, the answer is yes. The following figure plots global gas demand and gas supply up to 2030, suggesting that if the projects went ahead and supplies could reach the markets, then there would be a healthy gas supply surplus through to 2030.

Gasification and production projects can of course be delayed or occasionally advanced, and we all know that the economic cycle can give us a bumpy ride, but there is a clear message that natural gas has a global potential for sustained growth during the coming decades. Whilst in practice there may well be periods when it is more a buyers' or sellers' market, we have a clear expectation that supply can continue to satisfy demand in the long run. But, this is predicated on growing international and indeed inter-regional trade.

Inter-regional gas trade

Our global natural gas balance is the outcome of the different regional analyses. In terms of net importers, three regions stand out:

- **Europe** is, and will remain, by far the largest net importer; European net imports could exceed 440 bcm by 2030, a 58% increase compared to 2010 levels. Europe exports only small amounts of LNG from Snøvhit in Norway.
- Continental **Asia** is set to become the second largest importing region by 2030, driven by the growing energy requirements of China and India. Imports are multiplied eightfold, with around 270 bcm needed by 2030, compared to around 30 bcm in 2010. We can envisage some exports by pipeline from Myanmar to Asia Pacific.
- In third position in terms of imports stands **Asia Pacific**. This diverse area will continue to be a net importer, but the rapidly increasing demand in Japan, Korea and the South-East Asian region is partially compensated by the surge in Australian LNG exports. Net imports will almost double to around 80 bcm by 2030.

Figure 14
Global LNG Exports by Region
Source: IGU

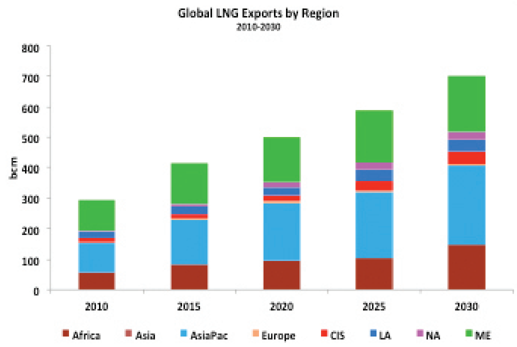
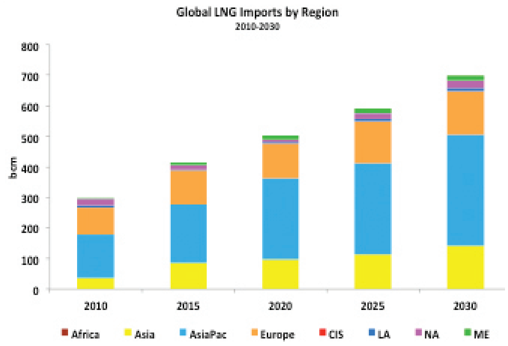


Figure 15
Global LNG Imports by Region
Source: IGU



Whilst the USA will establish and retain some LNG export potential, the North American region remains internally balanced. Latin America and the Caribbean will export around 30 bcm of LNG. In terms of direct trade, the whole of the Americas will remain only physically linked to the rest of the global gas market through LNG imports and exports.

Africa and the Middle East have a similar growth in terms of exports, reaching close to 200 bcm of net exports by 2030. The largest exporter remains the CIS region, with a doubling of its gas exports compared to 2010 reaching 370 bcm. These three regions export both LNG and pipeline gas, but only Africa and CIS do not import any gas from the other regions, while the Middle East may continue to remain an LNG importer.

LNG Trade

Global LNG trade is expected to more than double over the coming 20 years, increasing from 300 bcm in 2010 to 660 bcm by 2030. This requires a rapid build-up of liquefaction capacity around the world. There was already a first wave of new LNG capacity that arrived over 2009-11 with over 100 bcm of new LNG capacity coming on line, notably 63 bcm of LNG capacity from Qatar. The next wave will be coming mostly from Australia, Papua New Guinea and Indonesia with some 95 bcm of LNG export capacity having reached FID and expected to start over 2012-17.

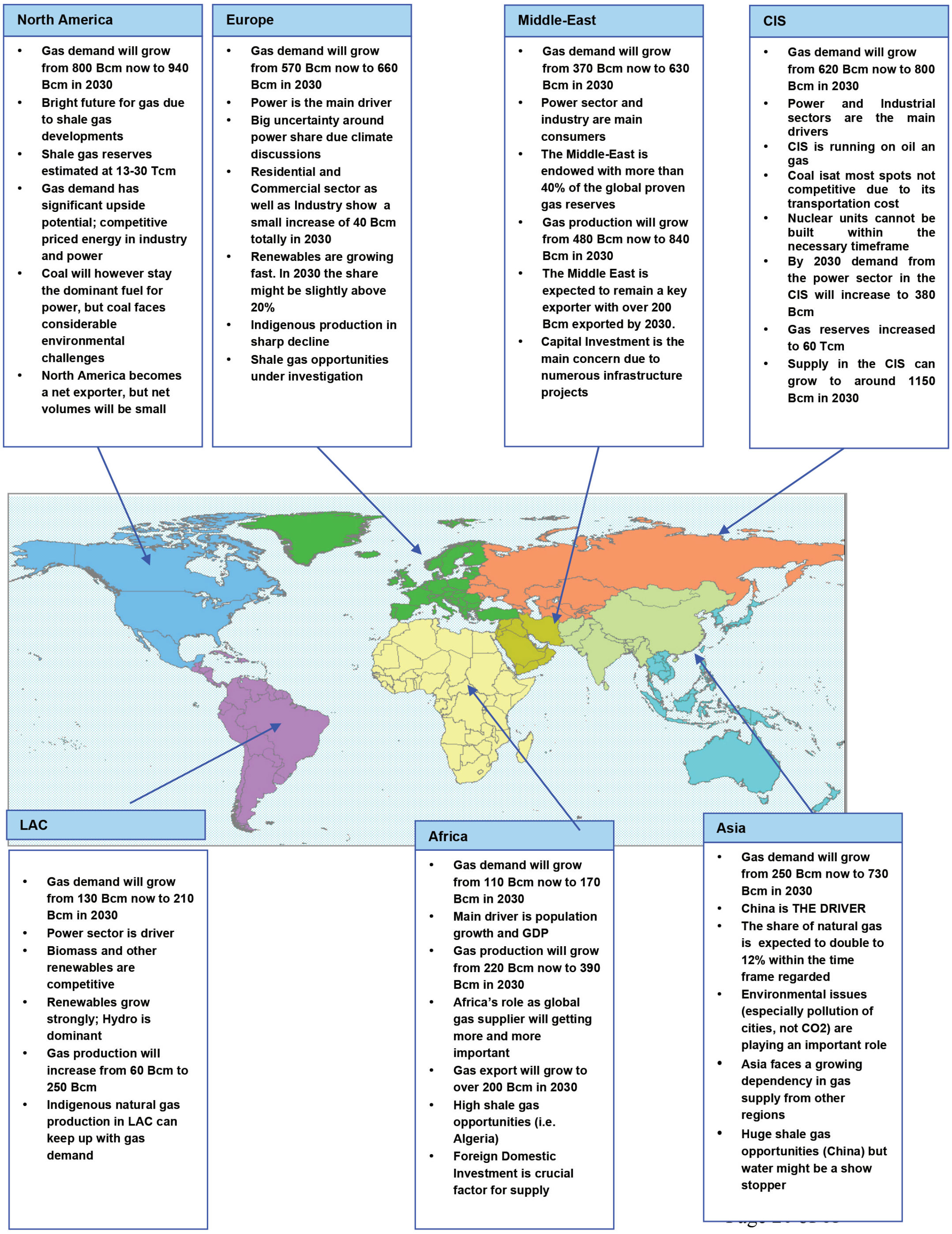
North American LNG exports are part of the IGU scenario, but never in very high volumes. Indeed, on a regional basis, the annual supply and demand are very much balanced, and the region continues to import some LNG (Mexico, Quebec) at the same time as it exports LNG (Western Canada, United States). The US LNG terminals may well also have a seasonal role; exporting when prices are sufficiently high in other parts of the world, but importing when the local gas supply/demand is tight and Henry Hub prices are high.

On the import side, Asia Pacific remains by far the largest LNG importer, representing around half of total LNG imports by 2030. Europe and Continental Asia follow but the two regions' combined LNG imports are still below that of Asia Pacific (around 140 bcm by 2030). Three other regions also import LNG, but in smaller quantities (below 20 bcm): North America, Latin America and the Middle East.

Overall Regional import/export balances

The figure on page 19 summarises the expected developments in global inter-regional gas trade in 2030. Only the main pipeline routes between IGU regions are shown. There are

Technical summary of regional gas supply and demand



also many international trade routes within each region, for example by high pressure pipeline from Canada to USA, which are not included on this map.

There are also ideas for other inter-regional links that we have not included; several of these may well go ahead if favourable economic and political conditions were to prevail.

Already we can see that based on identifiable projects inter-regional trade is set to increase. Trade within each region should also grow because of the shorter delivery routes and lower transportation costs. The world will need a lot of gas, whatever energy path we take in the coming decades. Investing in natural gas should be a ‘no regrets’ solution; a growing global gas market will be an increasingly important part of our sustainable energy future.

Part of this chapter is an update of the IGU Strategy Committee report on ‘new horizons for gas supply, demand and trade’ that was presented at the 25th World Gas Conference in Kuala Lumpur

Reserves and production

1. Global tables

Table 5.1

Natural gas: proved recoverable reserves at end-2011

Notes: The relationship between cubic metres and cubic feet is on the basis of one cubic metre = 35.315 cubic feet throughout

Sources: WEC Member Committees, 2009/10; data reported for previous WEC Surveys of Energy Resources; Cedigaz;Annual Report 2008, OAPEC; Annual Statistical Bulletin 2008, OPEC; Oil & Gas Journal, December 2009; World Oil, September 2009; published national sources

		Reserves	Production		R/P
Country	**bcm**	**bcf**	**bcm**		**years**
Afghanistan	50.0	1 765.7	45.5	1 607.6	1.1
Albania	1.0	35.3	3.0	105.9	.3
Algeria	4 502.0	158 987.1	84.6	2 988.0	53.2
Angola	161.0	5 685.7	.7	25.9	> 100
Argentina	332.5	11 742.5	45.5	1 607.6	7.3
Armenia	164.0	5 791.6			
Australia	788.6	27 849.2	45.0	1 588.8	17.5
Austria					
Azerbaijan	849.6	30 003.4	16.7	589.1	50.9
Bahrain	91.0	3 213.6	12.3	432.6	7.4
Bangladesh	183.7	6 487.3	20.1	710.9	9.1
Barbados					
Belarus	3.0	105.9			
Belgium					
Belize					
Benin	1.0	35.3			
Bhutan					
Bolivia	281.5	9 941.1	14.4	507.5	19.6
Bosnia-Herzegovina					
Botswana					
Brazil	459.4	16 223.3	24.1	852.5	19.0
Brunei Darussalam	390.8	13 801.0	11.8	416.7	33.1
Bulgaria	5.6	197.8			
Burkina Faso					
Burundi					
Cambodia					
Cameroon	135.1	4 771.0			
Canada	1 982.0	69 993.9	188.8	6 669.2	10.5
Cape Verde Islands					
Central African Republic					
Chad					
Chile	98.0	3 460.1	1.5	52.0	66.5
China	3 030.0	107 003.8	102.7	3 626.8	29.5
Colombia	134.1	4 735.7	11.3	397.6	11.9
Congo (DRC)	1.0	35.0			

Congo (Republic of)	90.6	3 199.5	1.2	41.0	78.0
Costa Rica					
Cote d'Ivoire	28.3	1 000.1	1.6	56.5	17.7
Croatia	24.0	846.1	1.8	64.0	13.2
Cuba	71.0	2 507.3	1.2	40.6	61.7
Cyprus					
Czech Republic	4.7	164.6	.2	6.0	27.6
Denmark	52.0	1 836.0	7.1	249.3	7.4
Dominican Republic					
Ecuador	7.9	279.0	.3	10.6	26.3
Egypt	2 186.0	77 198.1	61.3	2 165.9	35.6
El Salvador				.0	
Equatorial Guinea	36.8	1 299.6	6.7	238.0	5.5
Eritrea					
Estonia					
Ethiopia	25.0	882.9			
Faroe Islands					
Finland					
France	7.0	247.2	1.1	39.9	6.2
Gabon	29.0	1 024.1	8.0	282.5	3.6
Gambia					
Georgia	8.5	299.8			
Germany	79.5	2 806.3	12.9	454.6	6.2
Ghana	22.7	799.9			
Greece	1.0	35.0			
Greenland					
Guadeloupe					
Guatemala					
Guinea					
Guinea-Bissau					
Guyana					
Hong Kong					
Hungary	8.1	286.0	2.8	98.2	2.9
Iceland					
India	1 154.0	40 753.3	46.1	1 628.0	25.0
Indonesia	3 992.6	140 999.1	85.6	3 022.2	46.7
Iran	33 790.0	1 193 286.3	150.0	5 297.2	> 100
Iraq	3 158.0	111 524.1	.9	31.0	> 100
Ireland	10.0	353.1	.3	12.2	28.9
Israel	270.1	9 538.5	1.6	54.7	> 100
Italy	62.3	2 200.1	8.3	294.5	7.5
Jamaica					
Japan	40.0	1 412.6	5.0	176.3	8.0
Jordan	6.0	212.9	3.3	116.5	1.8
Kazakhstan	2 407.0	85 002.7	39.3	1 387.9	61.2
Kenya					
Korea (DRC)					
Korea (Republic)	7.1	250.0			
Kuwait	1 798.0	63 496.0	11.7	414.2	> 100
Kyrgyzstan	5.7	199.9			
Laos					
Latvia					
Lebanon					

Lesotho					
Liberia					
Libya	1 495.0	52 795.6	16.8	593.6	88.9
Lithuania					
Luxembourg					
Macedonia					
Madagascar					
Malawi					
Malaysia	2 350.0	82 989.7	66.5	2 348.4	35.3
Mali					
Malta					
Martinique					
Mauritania	28.0	988.8			
Mauritius					
Mexico	487.7	17 223.9	64.3	2 270.0	7.6
Moldova					
Monaco					
Mongolia					
Montenegro					
Morocco	1.4	50.9			
Mozambique	127.0	4 485.0	3.1	110.2	40.7
Myanmar (Burma)	283.2	10 001.1	11.9	421.0	23.8
Namibia	62.3	2 199.8			
Nepal					
Netherlands	1 303.0	46 015.2	81.1	2 863.7	16.1
New Caledonia					
New Zealand	27.6	976.1	4.4	154.2	6.3
Nicaragua					
Niger					
Nigeria	5 110.0	180 458.5	29.0	1 024.1	> 100
Norway	2 007.0	70 876.8	103.1	3 641.0	19.5
Oman	849.5	29 999.9	27.1	957.0	31.3
Pakistan	753.8	26 620.3	42.9	1 515.0	17.6
Papua New Guinea	155.3	5 484.4	.1	3.9	> 100
Paraguay					
Peru	352.8	12 459.1	31.0	1 094.8	11.4
Philippines	98.5	3 478.5	3.0	105.9	32.8
Poland	58.6	2 069.4	5.6	197.8	10.5
Portugal					
Puerto Rico					
Qatar	25 200.0	889 932.4	116.7	4 121.2	> 100
Réunion					
Romania	63.0	2 224.8	11.0	388.5	5.7
Russian Federation	47 750.0	1 686 280.6	669.6	23 646.8	71.3
Rwanda	56.6	1 999.9			
Saudi Arabia	8 028.0	283 507.0	99.2	3 504.3	80.9
Senegal					
Serbia					
Sierra Leone					
Singapore					
Slovakia	14.2	500.1			
Slovenia					
Somalia	5.7	199.9			

South Africa	27.1	957.0	1.0	34.3	27.9
Spain	2.5	89.7	5.0	176.6	.5
Sri Lanka					
Sudan	84.9	2 998.2			
Suriname					
Swaziland					
Sweden					
Switzerland					
Syria	240.7	8 499.9	8.9	315.7	26.9
Taiwan	6.9	243.7	.3	9.2	26.5
Tajikistan	5.7	200.0			
Tanzania	6.5	230.0	.8	27.5	8.4
Thailand	299.8	10 587.4	36.3	1 280.9	8.3
Togo					
Trinidad and Tobago	381.8	13 483.2	42.5	1 499.5	9.0
Tunisia	65.1	2 300.1	2.0	71.7	32.1
Turkey	7.1	250.7	.8	28.3	8.9
Turkmenistan	25 213.0	890 391.5	75.0	2 648.6	> 100
Uganda					
Ukraine	1 104.0	38 987.5	19.4	683.7	57.0
United Arab Emirates	6 089.0	215 031.7	51.3	1 810.9	> 100
United Kingdom	253.0	8 934.6	47.4	1 675.0	5.3
United States of America	7 716.0	272 488.8	648.5	22 901.9	11.9
Uruguay					
Uzbekistan	1 841.0	65 014.5	60.1	2 122.8	30.6
Venezuela	5 524.0	195 078.8	31.2	1 101.8	> 100
Vietnam	699.4	24 699.2	8.5	300.2	82.3
Yemen	478.5	16 898.1	6.2	220.4	76.7
Zambia					
Zimbabwe					
Total World	**209 741.9**		**3 517.8**		**59.6**

Table 5.2
Natural gas: production 2011

Notes: 1. Sources: WEC Member Committees, 2009/10; Cedigaz; national sources

	Reserves		Production		R/P
Country	**bcm**	**bcf**	**bcm**		**years**
Afghanistan	50.0	1 765.7	45.5	1 607.6	1
Albania	1.0	35.3	3.0	105.9	0
Algeria	4 502.0	158 987.1	84.6	2 988.0	53
Angola	161.0	5 685.7	.7	25.9	> 100
Argentina	332.5	11 742.5	45.5	1 607.6	7
Armenia	164.0	5 791.6			
Australia	788.6	27 849.2	45.0	1 588.8	18
Austria					
Azerbaijan	849.6	30 003.4	16.7	589.1	51
Bahrain	91.0	3 213.6	12.3	432.6	7
Bangladesh	183.7	6 487.3	20.1	710.9	9
Barbados					
Belarus	3.0	105.9			
Belgium					
Belize					

Benin	1.0	35.3			
Bhutan					
Bolivia	281.5	9 941.1	14.4	507.5	20
Bosnia-Herzegovina					
Botswana					
Brazil	459.4	16 223.3	24.1	852.5	19
Brunei Darussalam	390.8	13 801.0	11.8	416.7	33
Bulgaria	5.6	197.8			
Burkina Faso					
Burundi					
Cambodia					
Cameroon	135.1	4 771.0			
Canada	1 982.0	69 993.9	188.8	6 669.2	10
Cape Verde Islands					
Central African Republic					
Chad					
Chile	98.0	3 460.1	1.5	52.0	67
China	3 030.0	107 003.8	102.7	3 626.8	30
Colombia	134.1	4 735.7	11.3	397.6	12
Congo (DRC)	1.0	35.0			
Congo (Republic of)	90.6	3 199.5	1.2	41.0	78
Costa Rica					
Cote d'Ivoire	28.3	1 000.1	1.6	56.5	18
Croatia	24.0	846.1	1.8	64.0	13
Cuba	71.0	2 507.3	1.2	40.6	62
Cyprus					
Czech Republic	4.7	164.6	.2	6.0	28
Denmark	52.0	1 836.0	7.1	249.3	7
Dominican Republic					
Ecuador	7.9	279.0	.3	10.6	26
Egypt	2 186.0	77 198.1	61.3	2 165.9	36
El Salvador				.0	
Equatorial Guinea	36.8	1 299.6	6.7	238.0	5
Eritrea					
Estonia					
Ethiopia	25.0	882.9			
Faroe Islands					
Finland					
France	7.0	247.2	1.1	39.9	6
Gabon	29.0	1 024.1	8.0	282.5	4
Gambia					
Georgia	8.5	299.8			
Germany	79.5	2 806.3	12.9	454.6	6
Ghana	22.7	799.9			
Greece	1.0	35.0			
Greenland					
Guadeloupe					
Guatemala					
Guinea					
Guinea-Bissau					
Guyana					
Hong Kong					
Hungary	8.1	286.0	2.8	98.2	3

Iceland					
India	1 154.0	40 753.3	46.1	1 628.0	25
Indonesia	3 992.6	140 999.1	85.6	3 022.2	47
Iran	33 790.0	1 193 286.3	150.0	5 297.2	> 100
Iraq	3 158.0	111 524.1	.9	31.0	> 100
Ireland	10.0	353.1	.3	12.2	29
Israel	270.1	9 538.5	1.6	54.7	> 100
Italy	62.3	2 200.1	8.3	294.5	7
Jamaica					
Japan	40.0	1 412.6	5.0	176.3	8
Jordan	6.0	212.9	3.3	116.5	2
Kazakhstan	2 407.0	85 002.7	39.3	1 387.9	61
Kenya					
Korea (DRC)					
Korea (Republic)	7.1	250.0			
Kuwait	1 798.0	63 496.0	11.7	414.2	> 100
Kyrgyzstan	5.7	199.9			
Laos					
Latvia					
Lebanon					
Lesotho					
Liberia					
Libya	1 495.0	52 795.6	16.8	593.6	89
Lithuania					
Luxembourg					
Macedonia					
Madagascar					
Malawi					
Malaysia	2 350.0	82 989.7	66.5	2 348.4	35
Mali					
Malta					
Martinique					
Mauritania	28.0	988.8			
Mauritius					
Mexico	487.7	17 223.9	64.3	2 270.0	8
Moldova					
Monaco					
Mongolia					
Montenegro					
Morocco	1.4	50.9			
Mozambique	127.0	4 485.0	3.1	110.2	41
Myanmar (Burma)	283.2	10 001.1	11.9	421.0	24
Namibia	62.3	2 199.8			
Nepal					
Netherlands	1 303.0	46 015.2	81.1	2 863.7	16
New Caledonia					
New Zealand	27.6	976.1	4.4	154.2	6
Nicaragua					
Niger					
Nigeria	5 110.0	180 458.5	29.0	1 024.1	> 100
Norway	2 007.0	70 876.8	103.1	3 641.0	19
Oman	849.5	29 999.9	27.1	957.0	31
Pakistan	753.8	26 620.3	42.9	1 515.0	18

Papua New Guinea	155.3	5 484.4	.1	3.9	> 100
Paraguay					
Peru	352.8	12 459.1	31.0	1 094.8	11
Philippines	98.5	3 478.5	3.0	105.9	33
Poland	58.6	2 069.4	5.6	197.8	10
Portugal					
Puerto Rico					
Qatar	25 200.0	889 932.4	116.7	4 121.2	> 100
Réunion					
Romania	63.0	2 224.8	11.0	388.5	6
Russian Federation	47 750.0	1 686 280.6	669.6	23 646.8	71
Rwanda	56.6	1 999.9			
Saudi Arabia	8 028.0	283 507.0	99.2	3 504.3	81
Senegal					
Serbia					
Sierra Leone					
Singapore					
Slovakia	14.2	500.1			
Slovenia					
Somalia	5.7	199.9			
South Africa	27.1	957.0	1.0	34.3	28
Spain	2.5	89.7	5.0	176.6	1
Sri Lanka					
Sudan	84.9	2 998.2			
Suriname					
Swaziland					
Sweden					
Switzerland					
Syria	240.7	8 499.9	8.9	315.7	27
Taiwan	6.9	243.7	.3	9.2	27
Tajikistan	5.7	200.0			
Tanzania	6.5	230.0	.8	27.5	8
Thailand	299.8	10 587.4	36.3	1 280.9	8
Togo					
Trinidad and Tobago	381.8	13 483.2	42.5	1 499.5	9
Tunisia	65.1	2 300.1	2.0	71.7	32
Turkey	7.1	250.7	.8	28.3	9
Turkmenistan	25 213.0	890 391.5	75.0	2 648.6	> 100
Uganda					
Ukraine	1 104.0	38 987.5	19.4	683.7	57
United Arab Emirates	6 089.0	215 031.7	51.3	1 810.9	> 100
United Kingdom	253.0	8 934.6	47.4	1 675.0	5
United States of America	7 716.0	272 488.8	648.5	22 901.9	12
Uruguay					
Uzbekistan	1 841.0	65 014.5	60.1	2 122.8	31
Venezuela	5 524.0	195 078.8	31.2	1 101.8	> 100
Vietnam	699.4	24 699.2	8.5	300.2	82
Yemen	478.5	16 898.1	6.2	220.4	77
Zambia					
Zimbabwe					
Total World	**209 741.9**		**3 517.8**		**60**

2. Regional tables

Table 5.3
Natural gas: regional summary tables 2011

	Reserves	Production	R/P
Country	bcm	bcm	years
Nigeria	5110	29.0	> 100
Egypt	2186	61.3	36
Libya	1495	16.8	89
Angola	161.0	0.7	> 100
Cameroon	135		
Rest of region	631	22	
Africa total	9718.6	130.2	75
China	3030	102.7	30
Japan	40	5.0	8
Korea (Republic)	7		
Taiwan	7	0.3	27
Rest of region	0	0	
East Asia total	3084	108	29
Russian Federation	47750	669.6	71
Norway	2007	103.1	19
Netherlands	1303	81.1	16
Ukraine	1104	19.4	57
Bosnia-Herzegovina	282		
Rest of region	935	101	
Europe total	53381	974	55
Venezuela	5524	31.2	> 100
Brazil	459	24.1	19
Trinidad and Tobago	382	42.5	9
Peru	353	31.0	11
Argentina	333	45.5	7
Rest of region			
LAC total	7361	203	36
Iran	33790	150.0	> 100
Qatar	25200	116.7	> 100
Saudi Arabia	8028	99.2	81
United Arab Emirates	6089	51.3	> 100
Algeria	4502.0	84.6	53
Rest of region			
MENA total	84689	586	144
United States of America	7716	648.5	12
Canada	1982	188.8	10
Mexico	488	64.3	8
North America total	10186	902	11
Turkmenistan	25213	75.0	> 100
Kazakhstan	2407	39.3	61
Uzbekistan	1841	60.1	31
India	1154	46.1	25
Azerbaijan	850	16.7	51
Rest of region	1163	109	
South & Central Asia total	32627	345.7	94

Indonesia	3993	85.6	47
Malaysia	2350	66.5	35
Australia	789	45.0	18
Vietnam	699	8.5	82
Thailand	300	36.3	8
Rest of region	565	19	
Southeast Asia & Pacific	8695	261	33
Global totals	**206046.3485**	**3453.451889**	**60**

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 2011, OPEC;
- BP Statistical Review of World Energy, 2011;
- Energy Balances of OECD Countries, 2012 Edition, International Energy Agency;
- Energy Balances of Non-OECD Countries, 2012 Edition, International Energy Agency;
- Energy Statistics of OECD Countries, 2012 Edition, International Energy Agency;
- Energy Statistics of Non-OECD Countries, 2012 Edition, International Energy Agency;
- Natural Gas in the World, Cedigaz;
- Ex number of articles and other publications
- Numbers and estimates.

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

Note that Reserves/Production (R/P) ratios have been calculated on the basis of gross production less quantities re-injected.

Algeria

Proved recoverable reserves (bcm)	4 499
Production (bcm)	192.4
Consumption (bcm)	28.8
R/P ratio (years)	53.2

According to The Oil and Gas Journal (OGJ), as of January 2012, Algeria's proved natural gas reserves amount to 4 499 bcm, the tenth largest natural gas reserves in the world and the second largest in Africa - after Nigeria. Algeria is the third largest gas supplier to Europe.

Algeria's largest natural gas field is Hassi R'Mel, discovered in 1956. Located in the eastern part of the country, it holds proved reserves of about 2 405 bcm. The remainder of Algeria's natural gas reserves comes from associated locations (they occur alongside crude oil reserves) and non-associated fields in the south and southeast regions of the country.

Algeria's gross natural gas production in 2010 was 192.4 bcm compared with 195.27 bcm in 2009. Of this amount, 90.56 bcm was reinjected for enhanced oil recovery, 99.05 bcm was marketed, while 5.66 bcm was vented/flared.

According to Cedigaz estimates, Algeria's natural gas exports totalled 55.75 bcm in 2010, up from 52.63 bcm in 2009. About 65% of exports, or 36.5 bcm, moved through the natural gas pipelines connecting Algeria with Italy and Spain, while 35%, or 19.3 bcm, was exported by tankers as LNG. Algeria was the third largest natural gas supplier to Europe after Russia and Norway in 2010.

With the start-up of the LNG plant at Arzew in 1964, Algeria became the world's first producer of LNG. In 2010, the country was the seventh largest exporter of LNG in the world, accounting for about 7% of the world's total LNG exports. A new LNG plant with capacity of 218 bcf/y is under construction and due to open in 2013. Gas supplies will be coming from the Gassi Touil fields.

Argentina

Proved recoverable reserves (bcm	378.8
Production (bcm)	40.1
Consumption (bcm)	43.3
R/P ratio (years)	53.2

Argentina has the largest natural gas industry in South America, although its lead has been decreasing in recent years given the strong growth of its Brazilian competitor. It is also estimated that Argentine shale gas resources are the third largest in the world, after USA and China. About 13% of Argentina's 2011 natural gas was produced offshore and approximately 5% came from unconventional gas. The largest natural gas producing companies are Total and YPF which together account for about 50% of total production. Other companies with significant activities in the natural gas sector are Pan American Energy, Petrobras (Brazil), Pluspetrol (Argentina), Tecpetrol (Argentina), and Apache Energy (USA). Transportadora de Gas del Sur (TGS) is the leading natural gas transportation company followed by Transportadora de Gas del Norte (TGN).

Argentina is a net importer of natural gas, importing gas from Bolivia and exporting mainly to Chile and Uruguay. Exports of dry natural gas have dramatically fallen from its peak of 7.67 bcm in 2004 to 0.42 bcm in 2010. Argentina imported 21 LNG cargoes, or almost 1.1 million tonnes of LNG in 2010. Trinidad and Tobago accounted for nearly 90% of those imports, with the remainder arriving from Qatar. Argentine government tenders suggest that LNG imports doubled in 2011.

About 30% of natural gas produced in Argentina is used for power generation.

Australia

Proved recoverable reserves (bcm)	788.6
Production (bcm)	44.9
Consumption (bcm)	27.6
R/P ratio (years)	17.5

Natural gas is Australia's third largest energy resource after coal and uranium. This is unlikely to change up to 2035. Australia may also have significant shale gas resources but they have not been properly researched yet. At the moment there is no shale gas production in Australia. Nearly 92% of Australia's gas resources are located offshore on the North-West coast. Geoscience Australia and ABARE in their assessment of undiscovered conventional gas resources point towards the offshore basins with a total of 3228 bcm (114tcf). At the moment Australia has no proved reserves of tight gas, but identified in-place resources of tight gas are estimated to be (566 bcm or 20 tcf).

In 2010 Australia was the 4th largest LNG exporter in the world and around 48% of its gas production was exported as LNG. Japan accounted for nearly 70% of Australia's LNG exports, followed by China with 21% and South Korea with 5% (BP 2011).

Australia's LNG industry is undergoing a transformation and its capacity is expected to increase fourfold (113 bcm, 4 tcf). In addition to the current export capacity development, including the Pluto project which is scheduled to deliver first LNG exports in 2012, there is some 76 bcm (2.7 tcf) of capacity at various stages of construction. Three of these projects are based on conventional natural gas and located off the coast of Western Australia. Major domestic and foreign natural gas companies operating in Australia include Santos, Woodside, Chevron, ConocoPhillips, ExxonMobil, Origin Energy, BG Group, Apache, INPEX, Total and Shell.

Australia's gas consumption has been growing by 4% per year over the past decade. The main gas users in Australia are the manufacturing industry (32%), electricity generation (29%), mining (23%) and residential (10%) sectors.

At the end of April 2012 there were seven advanced gas-fired electricity generation projects under development with a combined capacity of 975 MW and scheduled to be in operation by the end of 2012 . Three of the projects are located in the Northern Territory while there is one each in New South Wales, Victoria, Queensland and Western Australia. In addition, there are further 42 gas- and CSG-fired generation projects at a less advanced stage with a combined capacity of around 1800 MW.

Azerbaijan

Proved recoverable reserves (bcm)	849.5
Production (bcm)	16.6
Consumption (bcm)	9.9
R/P ratio (years)	50.9

With the start of operations in the Shah Deniz natural gas and condensate field in late 2006, Azerbaijan became a net exporter of natural gas. Almost all of its natural gas is produced in two offshore fields, the ACG complex and Shah Deniz. The ACG field provides associated gas to the Azerigaz system for domestic use via an undersea gas pipeline to Sangachal Terminal at Baku. Azerbaijan is becoming an important supplier of both oil and natural gas. Companies involved in Azerbaijan's natural gas are Azerigaz, Azneft, AIOC, Statoil and BP, Total, LUKoil, SOCAR and OIEC of Iran.

About 66% of the country's total gas production is used to meet domestic demand and the remaining 34% are exported, mainly to Russia, Georgia and Turkey via the Gazi-Magomed-Mozdok pipeline. A small volume of natural gas is shipped to Iran via the Baku-Astara pipeline.

Bangladesh

Proved recoverable reserves bcm	183.7
Production (bcm)	20.1
Consumption (bcm)	20.1
R/P ratio (years)	19.1

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. Natural gas contributes nearly three-quarters of Bangladesh's commercial energy supplies and it is the main fuel in power stations and fertiliser plants.

Petrobangla (Bangladesh Oil, Gas and Mineral Corporation), a 100 per cent state owned corporation, has the primary responsibility for the natural gas industry in Bangladesh. Petrobangla is managed under the Ministry of Energy and Mineral Resources comprises several groups of companies covering the entire gas value chain: Bangladesh Petroleum Exploration Company, Bangladesh Gas Fields Company, Sylhet Gas Fields Company, Titas Gas Transmission and Distribution Company, Bakhrabad Gas System, Jalalabad Gas Transmission and Distribution System, Western Zone Gas Supply Co. (Poschim Anchal Gas Bitaran Company, WESGAS, a new company for distribution of gas in the western part of Bangladesh), and compressed natural gas company Rupantarita Prakritik Gas Company. Leading Private Companies Involved in the Natural gas industry include Libra Enterprise (www.libraenterprise.com), Gasmin Limited and Foundry Limited.

Bolivia

Proved recoverable reserves (bcm)	281.5
Production (bcm)	14.3
Consumption (bcm)	2.7
R/P ratio (years)	19.5

According to Oil & Gas Journal, Bolivia has the fifth largest reserves in South America. Most of these reserves are located in the eastern region of the country. The production volumes have risen dramatically since 1999.

Brazil is the primary destination for Bolivian natural gas. In 2010 about 68% of Bolivian natural gas was directed to Brazil via the GASBOL pipeline, and 20% to Argentina via the YABOG pipeline.

One-fifth of Bolivian natural gas production is consumed at the domestic market, mainly for electricity production (over one-half of Bolivian natural gas consumption), industry (roughly one-quarter) and transportation (just below one-fifth).

The state owned company YPFB (Yacimientos Petrolíferos Fiscales Bolivianos) and Petrobrás, Repsol YPF, Total, British Gas and British Petroleum and Exxon are the main actors in the market.

Brazil

Proved recoverable reserves (bcm)	459.3
Production (bcm)	24.1
Consumption (bcm)	26.7
R/P ratio (years)	26.5

Brazil's natural gas industry is still fairly new and relatively small compared to the oil sector. OGJ reported that Brazil had 14.7 trillion cubic feet (Tcf) of proved natural gas reserves in 2012. The Campos, Espírito Santo, and Santos Basins hold the majority of reserves, but there are sizable reserves also in the interior of the country. According to Petrobras, the Tupi field alone could contain 5-7 tcf of recoverable natural gas, which if proved, would increase Brazil's total natural gas reserves by 50 %. The other major natural gas market is located in Brazil is Amazon region.

Natural gas production has grown slowly in recent years, mainly due to the lack of domestic transport capacity and low domestic prices. In 2010, Brazil produced 445 billion cubic feet (bcf) of natural gas – the majority of this was associated with oil production. Natural gas consumption is a small part of the country's overall energy mix, accounting only for 7% of total energy consumption in 2010. The largest share of Brazil's natural gas is produced in offshore fields in the Campos Basin in Rio de Janeiro state.

Most of the onshore production takes place in the Amazonas and Bahia states and is used locally due to the lack of transportation infrastructure.

Brazilian gas pipeline network stretches over 4 000 miles, mostly in the South-East and North-East of the country.

With natural gas imports of 445 bcf in 2010, a 50% increase from 2009, Brazil is a major importer of natural gas and demand for gas is growing quickly. Imports are transported by the pipeline from Bolivia and as liquefied natural gas (LNG) from Trinidad and Tobago, Qatar and Nigeria. The anticipated growth of imports is expected to be supplied with LNG rather than with pipelines. Bolivia is the main natural gas supplier to Brazil and its share accounts for 78% of total gas imports. Currently, the main supplies from Bolivia are transported via the GASBOL pipeline, which links Santa Cruz in Bolivia to Porto Alegre in Brazil, via Sao Paulo.

Brazil has two liquefied natural gas (LNG) regasification terminals, both installed in the last two years: the Pecem terminal in the Northeast, and the Guanabara Bay terminal in the Southeast. Both facilities are floating regasification and storage units (FRSU), with a combined production capacity of 740 mcf per day. The Pecem received its first LNG cargo from Trinidad and Tobago in July 2008, while the Guanabara Bay terminal came online in May 2009. Petrobras plans to bring online a third terminal with a capacity of 495 mcf per day in Bahia state in 2013. State-owned Petrobras plays a dominant role in Brazil's entire natural gas supply chain. In addition to controlling the vast majority of the country's natural gas reserves, the company is in charge of the main domestic Brazilian gas production and for gas imports from Bolivia.

Brunei

Proved recoverable reserves (bcm)	390.8
Production (bcm)	11.8
Consumption (bcm)	2.9
R/P ratio (years)	33.1

Brunei is the third largest liquefied natural gas producer in Asia thanks to its strategic location close to the vital sea transport routes, through the South China Sea, linking the Indian and Pacific Oceans. Natural gas was found in association with oil at the Seria and other fields. For many years this resource was

virtually unexploited, but in the 1960s a realisation of the resource potential, coupled with the introduction of new production and transport technologies for liquefied natural gas, made it possible to develop a major gas export project. Since 1972 Brunei has been exporting LNG to Japan, and more recently to Korea. Occasional spot market sales have been agreed and delivered to other destinations, too. About 70% of Brunei's marketed production is exported as LNG, 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)	1727.0
Production (bcm)	160.1
Consumption (bcm)	103.3
R/P ratio (years)	10.5

Canada is the world's third-largest producer of dry natural gas and has for many years been the source of most US natural gas imports, before the recent shale gas revolution in the US market. Canada's gas in place from both conventional and unconventional resources is estimated to be almost 113 200 bcm, (Petrel Robertson, 2010).

Despite holding a relatively small share of the world's proved natural gas reserves, Canada is the fourth-largest exporter of natural gas, behind Russia, Norway, and Qatar. All of Canada's current natural gas exports are sent to U.S. markets via pipeline. The proportion of Canada's natural gas production that is devoted to meeting domestic requirements has risen in recent years, while net exports to the United States have fallen. Most of Canada›s natural gas reserves are conventional resources in the WSCB, including those associated with the region›s oilfields.

Other areas with significant concentrations of natural gas reserves include offshore fields near the eastern shore of Canada, principally around Newfoundland and Nova Scotia, the Arctic region, and the Pacific coast. EIA estimates that Canada produced 189.67 bcm of gross natural gas in 2010 of which 166.9 bcm was marketed; 152.8 bcm was dry natural gas), 20.44 bcm was reinjected, and 1.54 bcm was vented or flared.

Canada's natural gas pipeline system is highly interconnected with the U.S. pipeline system. TransCanada operates the largest network of natural gas pipelines in North America, including thirteen major pipeline systems and approximately 37,000 miles of gas pipelines in operation.

A number of major and independent companies, including Encana, Apache, Devon, Quicksilver, and Nexen, are involved in Canada's natural gas industry.

China

Proved recoverable reserves (bcm)	3 030
Production (bcm)	102.7
Consumption (bcm)	130.9
R/P ratio (years)	40.6

The major producing gas fields in China are located in the Sichuan Basin (output of 17 bcm in 2007), the Ordos Basin (15.5 bcm) and the Tarim Basin (12 bcm). According to provisional estimates, in 2008, China's natural gas consumption grew by 11.8% and reached 77.7 bcm. Since 2004, the annual growth was more than 20%, far above the country's GDP growth rate.

With the exception of its own consumption in the energy sector, which uses gas mainly for the development of oil and gas fields, the chemicals and petrochemicals industries are major natural gas consumers in the industrial sector. Natural gas is used as a fuel and feedstock in several industries such as ammonia, methanol and chemical fertilizer production. According to the government's long-term electricity development plan, gas-fired power capacity is expected to reach 70 GW by 2020.

As in the oil industry, China's upstream natural gas sector is dominated by three national Oil Companies (NOCs): CNPC, Sinopec and CNOOC. CNPC now holds approximately 75%

of all domestic gas resources and 80% of China's pipeline network (including major inter-provincial trunk lines). CNPC is also in charge of several major gas import projects, such as the Central Asia pipeline and LNG imports in Jiangsu and Dalian.

There are also a few small-size natural gas producers – mainly owned by local governments. More recently, small-size inland LNG producers operated by private companies have also entered the scene. In Xinjiang, for example, a new private company recently built a small LNG plant with production capacity of 0.6 bcm (432 000 tonnes) per year and delivery of LNG by tanker trucks.

Most distribution companies are owned and managed by local governments, while producers directly deliver natural gas to major industrial users. In 2002, the government opened the city gas business to private and foreign companies, and as a result more than 60 private companies are now involved in distributing gas in several cities, including Shanghai and Guangdong. LNG receiving terminals are owned and operated by joint ventures between local government entities, gas users and importing NOCs, such as CNOOC and CNPC.

Colombia

Proved recoverable reserves (bcm)	134.1
Production (bcm)	11.26
Consumption (bcm)	9.08
R/P ratio (years)	11.2

According to the Oil and Gas Journal, Colombia had proved natural gas reserves of 4.7 trillion cubic feet (Tcf) in 2012, up from 4 Tcf in 2011. 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.

The bulk of Colombia's natural gas reserves are located in the Llanos basin, although the Guajira basin accounts for the major part of current production. Natural gas production, like oil production, has been rising substantially in the last few years due to increasing international investment in exploration and development, rising domestic consumption, and new export opportunities. The two biggest natural gas fields in the country, the Cupiaga and Cusiana fields in the Llanos basin, in central Colombia, were acquired from BP by Ecopetrol and Talisman Energy in 2010. Almost all of the gas produced from these fields is re-injected.

Colombia produced 398 billion cubic feet (Bcf) of dry natural gas in 2010, while consuming 321 Bcf. About 57 % of the country's total gross natural gas production of 1,124 Bcf was reinjected to facilitate enhanced oil recovery.

There are some 2,000 miles of natural gas pipelines in Colombia. Empresa Colombiana de Gas (Ecogás) operates most of Colombia's natural gas pipeline network. The three main lines include the Ballena-Barrancabermeja, linking Chevron's Ballena field on the northeast coast to Barrancabermeja in central Colombia; the Barrancabermeja-Nevia-Bogota line, which integrates the Colombian capital into the transmission network, and the Mariquita-Cali line through the western Andean foothills.

Chevron is the largest natural gas producer in the country, producing on average 642 Mcf gross natural gas daily and supplying about 65 % of the country's needs. In partnership with Ecopetrol, the company operates the offshore-Caribbean Chuchupa field in the Guajira basin, the largest non-associated natural gas field in the country.

At present a high proportion of Colombia's gas output (42% in 2008) is re-injected in order to maintain or enhance reservoir pressures. The major outlets for natural gas are own use by the petroleum industry (23% of total gas consumption in 2007), chemicals, cement and other industrial users (27%) and power plants (25%). Residential/commercial consumers accounted for 20%, while CNG use in road transport is still of modest proportions.

Denmark

Proved recoverable reserves (bcm)	51.9
Production (bcm)	7.1
Consumption (bcm)	4.1
R/P ratio (years)	7.3

The Danish WEC Member Committee reports data provided by the Danish Energy Authority (DEA), which does not use the terms 'proved', 'probable', 'possible' and 'additional' reserves, but employs the categories 'ongoing', 'approved', 'planned' and 'possible' recovery. The DEA expresses natural gas volumes in normal cubic metres (Nm3), measured at 0oC and 1 013 mb. For the purpose of the present Survey, all such data have been converted into standard cubic metres, measured at 15oC and 1 013 mb.

Denmark is a net exporter of natural gas. In 2010 it exported approximately 3.2 bcm of gas: 46% to Sweden, 32% to Germany and the rest to the Netherlands.

Today, all natural gas for the Danish market comes from the fields in the Danish sector of the North Sea. DONG has purchased all the gas produced from the Danish fields. The biggest producer of natural gas in Denmark is Dansk Undergrunds Consortium (DUC), which produces gas from a number of fields. In addition, the South Arne Group produces natural gas from the South Arne field.

DONG purchases and transports all natural gas for the Danish market and also distributes gas to customers in Southern Jutland and parts of Zealand. DONG is a state-owned limited company. HNG distributes natural gas in the Greater Copenhagen Area. In Central and North Jutland, natural gas is distributed by Naturgas MidtNord, and on Funen, it is distributed by Naturgas Fyn.

The major part of the national consumption is related to gas-fired CHP plants, manufacturing industries and the residential/commercial sector.

Egypt (Arab Republic)

Proved recoverable reserves (bcm)	2186
Production (bcm)	61.3
Consumption (bcm)	46.2
R/P ratio (years)	35.6

In January 2012, OGJ estimated Egypt's proved gas reserves to reach 77 Tcf, a significant increase compared to the 2010 estimates of 58.5 Tcf. In terms of the natural gas reserves, Egypt ranks third in Africa, after Nigeria and Algeria.

New discoveries offshore the Nile Delta and some finds in the Western Desert have led to the increase in proved reserves. Over 80% of Egypt's natural gas reserves and 70% of its production are located in the Mediterranean and the Nile Delta.

In 2010, Egypt produced roughly 2.2 Tcf and consumed just over 1.6 Tcf of dry natural gas. Gas production is expected to continue to grow to satisfy rising domestic demand, export commitments through the Arab Gas Pipeline and LNG exports. Egypt is expected to continue to play an important role of a reliable natural gas supplier to Europe and the Mediterranean region, although exports are competing with rising domestic demand, particularly in the power generation sector.

The electricity sector accounted for the largest share of natural gas consumption (54%) followed by the industrial sector (29 %), according to Cedigaz. The share of natural gas consumed in the transportation sector has also been rising since the development and deployment of compressed natural gas (CNG) infrastructure and vehicles. According to the Ministry of Petroleum of Egypt, the number of natural gas driven vehicles sold in Egypt between the fiscal years 2004/2005 and 2009/2010 has more than doubled. Major foreign players involved in the development of Egypt gas sector include Eni, BG Group, BP & Apache and GASCO.

Dry natural gas exports, which began in 2003, have been rising rapidly, with the completion of the Arab Gas Pipeline (AGP) in 2004 and the startup of the first three LNG trains at Damietta in 2005. However, after 2006 exports began to level off and in 2010, natural gas exports fell to 535 Bcf, an almost 20 % drop from the year before. Egypt exports around 70% of total natural gas exports as LNG, and the remaining 30% are exported via pipelines. The Arab

Gas Pipeline (AGP) originates in Egypt and provides gas to Jordan, Syria and Lebanon, with recent additions extending the pipeline to Turkey and European markets. Egypt has three LNG trains: Segas LNG Train 1 in Damietta and Egypt LNG trains 1 and 2 in Idku. The combined LNG export capacity is close to 600 Bcf per year with plans to expand in the near future, pending export policy changes and legislation. In 2010, as domestic demand for natural gas increased, LNG exports fell to about 354 Bcf, which was down by 30% from almost 500 Bcf in 2009.

In 2010 half of Egypt's LNG was shipped to Europe, which imported about 180 Bcf, with over half of that destined for Spain (110 Bcf). The US was the second largest recipient of Egyptian LNG in 2010, and imported just over 71 Bcf. Other major destinations included Korea (36 Bcf), Japan (21 Bcf) and Chile (18 Bcf). The recent advances in shale gas technologies are fundamentally changing the natural gas sector's business model and in particular in the North-American market and these changes will have a significant impact on Egypt's future economic development and the entire market

Germany

Proved recoverable reserves (bcm)	175.6
Production (bcm)	11.9
Consumption (bcm)	79.0
R/P ratio (years)	14.7

Despite the country being one of Europe's oldest gas producers, Germany's remaining proved natural gas reserves are still sizeable, and (apart from the Netherlands) they 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 in the vicinity of the Netherlands border there is another main producing zone, with more mature fields.

Indigenous production provides roughly 20% of Germany's gas supplies; the greater part of demand is met by imports from the Russian Federation, Norway, the Netherlands, Denmark and the UK. Germany imports 87.57 bcm natural gas. Due to its central location in Europe, Germany is a major natural gas pipeline transit hub for imports from Russia and the North Sea. The main suppliers of natural gas include E.ON, RWE, Wingas, VNG.

India

Proved recoverable reserves (bcm)	1154
Production (bcm)	46.1
Consumption (bcm)	61.1
R/P ratio (years)	25.0

The Indian gas market is expected to be one of the fastest growing in the world over the next two decades. IEA envisages gas demand to increase by 5.4% per annum over 2007-30 (IEA, 2009) reaching 132 bcm by 2030. India's primary energy supply is currently dominated by coal (37%), biomass and waste (27%) and oil (26%) while the share of natural gas is only 6%.

Production has been almost flat since 2002, at 30-32 bcm per year, but jumped to 46 bcm in 2009-2010. Around three quarters of the gas production came from the Western offshore area. Fields located in Gujarat, Assam and Andhra Pradesh are the major sources of onshore gas. Smaller quantities of gas are also produced in Tamil Nadu, Tripura and Rajasthan.

India's natural gas sector, just as the entire energy sector, is dominated by state-owned companies. The Oil and Natural Gas Corporation (ONGC) and Oil India Ltd (OIL) have dominant upstream positions. A handful of Indian and foreign companies such ONGC, BP, RIL, Essar Oil, Arrow Energy, GAIL, and GEECL are active in India's natural gas sector.

There are two main gas transport companies: the former public sector monopoly GAIL and a new entrant, Reliance Gas Transportation Infrastructure Ltd (RGTIL), a company privately owned by Reliance Industries Ltd. As India does not have any pipeline connections, all gas is currently imported as LNG. Current operational LNG import capacity is 13.5 mtpa (18 bcm).

India imports natural gas from Qatar (under a long-term contract), Australia, Trinidad and Tobago, and Russia as well as from a few other countries. Natural gas is mainly used as fuel for power generation and currently its share in the electricity production fuel mix, is according to the Central Electricity Authority (CEA), with gas representing 11% versus 52% for coal and 24% for hydro.

There are an estimated 700 000 natural gas vehicles (NGV) in India making India the fifth country after Pakistan, Argentina, Brazil and Iran in terms of NGVs.

Indonesia

Proved recoverable reserves (bcm)	3994
Production (bcm)	82.8
Consumption (bcm)	41.3
R/P ratio (years)	48.3

According to Oil & Gas Journal, Indonesia had 141 trillion cubic feet (Tcf) of proved natural gas reserves as of January 2012, making it the 14th largest holder of proved natural gas reserves in the world, and the third largest in the Asia-Pacific region. The country continues to be a major exporter of pipeline and liquefied natural gas (LNG). At the same time, domestic consumption of natural gas has nearly doubled since 2004. Natural gas shortages caused by production problems and rising consumption forced Indonesia to buy spot cargoes of LNG to meet export obligations. The government committed to constructing new LNG receiving terminals and gas transmission pipelines to address domestic gas needs, though this could reduce the natural gas available for export.

Indonesia's gas production is the highest in Asia. The main producing areas are in northern Sumatra, Java and eastern Kalimantan. Natural gas production has increased by over a third since 2005. While Indonesia still exports about half of its natural gas, domestic consumption is increasing. Indonesia has for many years been the world's leading exporter of LNG.

The principal domestic consumers of natural gas (apart from the oil and gas industry) are power stations, fertiliser plants and industrial users; the residential, commercial and transportation sectors have relatively small shares.

The state corporation Pertamina accounted for less than 15 % of natural gas production in 2012, according to PwC. International oil companies such as Total, ConocoPhillips and

ExxonMobil dominate the upstream gas sector, while the state-owned utility Perusahaan Gas Negara (PGN) carries out natural gas transmission and distribution activities.

In 2011, Indonesia produced 2.7 Tcf of dry natural gas. Production grew at an annual rate of about 2% over the previous two decades, and Indonesia's 2011 gas production was the eleventh-highest in the world. A little more than half of Indonesia's 2011 production came from offshore fields, according to the Ministry of Energy and Mineral Resources. The government estimates that more than 60 % of the country's conventional gas reserves may be located offshore. An increasingly large share of Indonesia's natural gas production has come from non-associated (purely natural gas) fields in recent years. According to IHS Global Insight, associated gas (found in oil fields) accounted for around 15 % of gross production in 2010. Indonesia's largest fields are located in the Aceh region of South Sumatra and East Kalimantan. Natural gas associated with oil production is often flared when there is no infrastructure in place to make use of the gas. Indonesia ranks tenth in global natural gas flaring according to the Global Gas Flaring Reduction (GGFR) Initiative, but its flaring volume has dropped in recent years from a high of over 175 billion cubic feet (Bcf) in 1997 to around 80 Bcf in 2010, according to satellite data from the National Oceanic and Atmospheric Administration (NOAA)

In 2011, Indonesia consumed 1.3 Tcf of natural gas, or just under half of its total dry gas production. Although the industrial sector accounts for the largest portion of domestic consumption, industry analysts expect the power sector to be the most significant driver of future consumption growth.

Indonesia was the world's eighth largest net exporter of natural gas in 2011. The majority of exports go to Japan as LNG shipments and to Singapore via pipeline connections

Indonesia was the third-largest exporter of liquefied natural gas (LNG) in 2011, following Qatar and Malaysia, according to data from PFC Energy. By year end 2011, Indonesia exported over 1 Tcf of LNG, or about nine % of the world's LNG exports. Mostly a regional supplier to Japan, South Korea, Taiwan, and China, Indonesia lost market share in recent years to LNG producers such as Qatar, Malaysia, Australia, and Algeria.

There are three operational liquefaction terminals in Indonesia, with a combined production capacity of about 1.6 trillion cubic feet per year (Tcf/y). The Bontang LNG terminal in East Kalimantan has a capacity of 1.1 Tcf/y; it is the largest in Indonesia and one of the largest in the world

The next anticipated LNG facility in Indonesia will be the Donggi-Senoro liquefaction plant in Central Sulawesi. The project developers (Mitsubishi, Kogas, Pertamina, and Medco) signed a final investment decision in early 2011 expect the 370 Bcf/y plant to be commercial in 2014. Inpex, a Japanese company, received government approval at the end of 2010 for the Masela liquefaction terminal in the Arafura Sea, but it has delayed the expected startup date of the floating terminal until 2018

Iran (Islamic Republic)

Proved recoverable reserves (bcm)	3 307
Production (bcm)	146.1
Consumption (bcm)	144.6
R/P ratio (years)	22.63

Iran has the second largest gas reserves in the world after the Russian Federation. For two decades, its production growth increased by an average of 10% per annum, yet Iran has only depleted 5% of its gas reserves.

According to Oil & Gas Journal, as of January 2011, Iran's estimated proved natural gas reserves stood at 29601.8 bcm, second only to Russia. Over two-thirds of Iranian natural gas reserves are located in non-associated fields, and have not been developed. Major natural gas fields include: South and North Pars, Kish, and Kangan-Nar.

Iran's natural gas reserves are predominantly located offshore, although significant production originates from onshore oil fields (associated gas). Over two-thirds of Iranian natural gas reserves are located in non-associated fields, and are just recently beginning to be developed. The giant South Pars gas field, only a portion of which is in Iranian territory, comprises over 47% of total reserves. Other large natural gas fields include North Pars, Kish, Kangan-Nar, Golshan, and Ferdowsi fields. USGS estimates that Iran's undiscovered gas resources could be 5660 – 22640 billion cubic meters.

Iran imports natural gas from its northern neighbour Turkmenistan. According to FGE imports jumped to 1.1 Bcf/d between January and October 2011 as a result of completion of the Dauletabad-Hasheminejad pipeline. Iran exports natural gas to Turkey and Armenia via pipeline.

The most significant energy development project in Iran is the offshore South Pars field, which produces about 35% of total gas produced in Iran.

POGC is responsible for LNG development, although various companies including the National Iranian Gas Export Company (NIGEC) are also involved.

Iraq

Proved recoverable reserves (bcm)	3138
Production (bcm)	1.3
Consumption (bcm)	1.3
R/P ratio (years)	2423

Iraq's natural gas resources are not particularly large by Middle Eastern 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, which gives Iraq's proved reserves as 2 577 bcm.

According to data reported by Cedigaz, Iraq also possesses 5 009 bcm of probable and possible reserves, and states that 70% of Iraq's proved reserves consist of associated gas, with non-associated gas accounting for 20% and dome gas for the balance. 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.

Iraq's proven reserves of conventional natural gas amount to 3.4 trillion cubic metres (tcm), or about 1.5% of the world total, placing Iraq 13th among global reserve-holders.

Geographically, Iraq's proved gas reserves are concentrated in the South, mostly as the large associated gas reserves in the super-giant fields of Rumaila, West Qurna, Majnoon, Nahr Umr and Zubair. Power sector is the main industrial activity sector for gas use, followed by domestic use. Natural gas companies operating in Iraq are Basrah Gas Company (BGC), Shell and Mitsubishi.

Iraq currently imports natural gas from Iran and the countries are building a gas pipeline expected to be operational next year.

Kazakhstan

Proved recoverable reserves (bcm)	2407
Production (bcm)	20.2
Consumption (bcm)	10.2
R/P ratio (years)	119

Kazakhstan has substantial resources of natural gas and may well become a major player on the world stage. In January 2012, the Oil and Gas Journal estimated Kazakhstan's proved natural gas reserves at 85 trillion cubic feet (Tcf). Natural gas production in Kazakhstan is almost entirely associated gas. 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.

Annual marketed natural gas production has been trending upward from 314 billion cubic feet (Bcf) in 2000 to 388 Bcf in 2009, before it decreased slightly in 2010. While total gross gas production was 1.3 Tcf in 2010, 75 % of the gas produced was re-injected into oil fields to enhance production. The two largest natural gas producing fields are also the largest oil producing fields.

The Karachaganak oil and gas field produced approximately half of Kazakhstan's total gross gas production, totaling about 650 Bcf in 2010. Oil and Gas Journal reported that its production jumped to 784 Bcf in 2011. Wood Mackenzie expects that dry gas production from the Karachaganak field will reach 775 Bcf in 2015 and 1.3 Tcf in 2020.

The Tengiz oil and gas field produced approximately 300 Bcf gross natural gas during 2011, of which 114 was dry gas production, according to Chevron. According to Wood Mackenzie projections, Tengiz will continue to play a significant role in Kazakhstan's gas production and will reach 623 Bcf of dry gas in 2015

Since 2008, Kazakhstan has been producing sufficient volume of dry natural gas to satisfy its domestic demand

Kazakhstan has two separate domestic natural gas distribution networks, one in the west, which services the country's producing fields, and one in the south, which mainly delivers imported natural gas to the consuming regions. Kazakhstan's pipeline network consists of 11,000 kilometers of pipeline, 22 compressor stations, and three underground storage facilities. The main pipelines are the Central Asia Center pipeline, the Bukhara-Ural pipeline, Tashkent-Almaty pipeline, and the Turkmenistan-China pipeline. Kazakhstan currently serves mainly as a transit country for natural gas pipeline exports from Uzbekistan and Turkmenistan to Russia and China.

Kuwait

Proved recoverable reserves (bcm)	1798
Production (bcm)	11.73
Consumption (bcm)	12.62
R/P ratio (years)	153.28

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. With the exception of World Oil, which quotes 1 877 bcm, all the main publications give end-2008 levels falling inside a very narrow range (1 780-1 800). According to Oil & Gas Journal, as of January 2011, Kuwait had an estimated 63 trillion cubic feet (Tcf) of proved natural gas reserves. Kuwait's reserves are not significant and this has spurred an extensive drive in natural gas exploration. Kuwait has recently become a net importer of natural gas, leading the country to focus more on natural gas exploration and development for domestic consumption.

As in the oil sector, all of the natural gas resources are owned by the Kuwait Petroleum Corporation (KPC). The Kuwaiti constitution prohibits any use of production-sharing agreements (PSAs) that allow for an equity stake by an IOC in development projects. Therefore, Kuwait is using technical service agreements (TSAs) in order to bring in IOCs to develop more difficult projects.

In February 2010, Shell announced the signing of an agreement with the Kuwait Oil Company under which Shell will provide technical support to KOC in the development of the Jurassic Gas fields of non-associated gas in the northern part of the country. After allowing for a limited amount of flaring and for shrinkage due to the extraction of NGLs, Kuwait's gas consumption is currently 12-13 bcm/yr, nearly one-third of which is used for electricity generation and desalination of seawater.

In 2010, Kuwait produced 1.17 billion cubic feet per day (Bcf/d) of natural gas. This volume was an increase of around 8 % compared with 2009. Given the predominance of associated natural gas in Kuwaiti production, domestic natural gas supplies decreased as a result of lower OPEC crude production quotas. Kuwait increasingly requires supplies of natural gas for the generation of electricity, water desalination, and petrochemicals, as well as increased use for enhanced oil recovery (EOR) techniques to boost oil production. In 2010, Kuwait consumed approximately 529 Bcf of natural gas, which is equal to 1.45 Bcf/d. Since 2008, Kuwait has consumed more natural gas than it has produced. This has compounded the problem of electricity outages by making the availability of feedstock precarious.

In 2010, Kuwait imported 270 MMcf/d of LNG, largely from regional neighbors, Yemen and Oman. Kuwait has also recently exhibited interest in supplies from the impending natural gas project in Southern Iraq

In June 2009, Kuwait signed a deal with Shell to import LNG, receiving the first cargo in August 2009. KPC made another deal with international energy trading firm, Vitol, in April 2010, which will supply Kuwait with LNG cargoes through 2013. Kuwait takes delivery of the LNG at the Persian Gulf's first regasification terminal, Mina al-Ahmadi GasPort. The regasification capacity of al-Ahmadi is approximately 500MMcf/d of LNG.

Libya/GSPLAG

Proved recoverable reserves (bcm)	1495
Production (bcm)	16.81
Consumption (bcm)	6.84
R/P ratio (years)	88.9

Libya is an important exporter of natural gas. Proved reserves - the fourth largest in Africa - have been largely unchanged since 1991, according to OAPEC and other published sources, which – in a rare instance of unanimity – all quote the same figure.

Since 1970 Libya has operated a liquefaction plant at Marsa el Brega, but LNG exports (in recent years, solely to Spain) have fallen down to only 0.5 bcm/year. Libyan natural gas production and exports to Europe increased considerably since 2003, with the development of offshore fields and opening of the 370-mile Greenstream underwater pipeline from Melitah to Gela in Sicily. Libya is a direct producer and distributor in Italy, Germany, Switzerland and Egypt and exports 9.97 bcm of natural gas.

Natural gas companies in Libya include NOC, ENI, Akakus oil operations, Oillinvest, Gatoil, Tamoil.

Natural gas currently accounts for 45% of fuel for electricity generation. Projects under development include the 800-megawatt power plant in Zwara (Zuwarah), a 600-megawatt Western Mountain Power Project, a 1,400-megawatt power plant to be located on the coast between Benghazi and Tripoli, and the 1,200-megawatt Gulf Stream combined power and desalination complex in Sirt.

Power stations, petrochemical/fertiliser plants and oil/gas industry are the main users of natural gas.

Malaysia

Proved recoverable reserves (bcm)	2350
Production (bcm)	66.5
Consumption (bcm)	35.7
R/P ratio (years)	35.3

According to the Oil and Gas Journal, Malaysia held 83 trillion cubic feet (Tcf) of proved natural gas reserves as of January 2011, and was the fourth largest natural gas reserves holder in the Asia-Pacific region. Most of the country's natural gas reserves are located in Eastern areas, predominantly offshore Sarawak. Exploration of Malaysia's offshore waters has discovered 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) stand at 2 330 bcm and rank as the fourth largest in Asia. Other published reserve assessments, whilst not identical, have moved much closer to Cedigaz. They now range from Oil & Gas Journal's 2 350 bcm, via BP at 2 390, to OPEC's 2 475 and World Oil's 2 506.

Gross natural gas production has been rising steadily, reaching 2.7 Tcf in 2010, while domestic natural gas consumption has also increased steadily, reaching 1.1 Tcf in 2010, 42% of production. There are several important ongoing projects that will expand natural gas production in Malaysia even further over the near term. Exploration and development activities in Malaysia continue to focus on offshore Sarawak and Sabah. One of the most active areas for natural gas exploration and production is the Malaysia-Thailand Joint Development Area (JDA), located in the lower part of the Gulf of Thailand. The JDA reportedly holds 9.5 Tcf of proved plus probable natural gas reserves.

Malaysia became a major gas producer in 1983, when it begun to export LNG to Japan. Gas exports have grown ever since, and in recent years the Republic of Korea, Taiwan, and China have become important markets for Malaysian gas supplies via pipeline to Singapore.

Malaysia was the third largest exporter of LNG in the world after Qatar and Indonesia in 2010, exporting over 1 Tcf of LNG, which accounted for 10 % of total world LNG exports. LNG is primarily transported by Malaysia International Shipping Corporation (MISC), which owns and operates 27 LNG tankers, the single largest LNG tanker fleet in the world by volume of LNG carried. MISC is 62-% owned by Petronas.

Domestic consumption of gas has become significant in recent years, in particular in power generation. The other major use of natural gas, apart from own use within the oil/gas industry, is as feedstock/fuel for industrial users. Relatively small amounts of CNG are used in transport, reflecting an official programme to promote its use.

As in the oil sector, Malaysia's state-owned Petronas dominates the natural gas sector. The company has a monopoly on all upstream natural gas developments, and also plays a leading role in downstream activities and the LNG trade. Most natural gas production comes from production-sharing agreements operated by foreign companies in conjunction with Petronas.

The Bintulu LNG complex on Sarawak is the main hub for Malaysia's natural gas industry. Petronas owns majority interests in Bintulu's three LNG processing plants, which are supplied by offshore natural gas fields. The Bintulu facility is the largest LNG complex in the world, with 8 production trains and a total liquefaction capacity of 1.7 Tcf per year following the debottlenecking completed at end-2010, which raised overall capacity by 0.6 Tcf per year.

Mexico

Proved recoverable reserves (bcm)	490.3
Production (bcm)	55.1
Consumption (bcm)	59.1
R/P ratio (years)	8.89

According to OGJ, Mexico had 17.3 trillion cubic feet (Tcf) of proved natural gas reserves as of the end of 2011, a sharp increase of more than 5 Tcf from the year before. The Southern region of the country contains the largest share of proved reserves. However, the Northern region will likely be the center of future reserves growth, as it contains almost ten times as much probable and possible natural gas reserves as the Southern region. Mexico has considerable natural gas resources, but its production pales in comparison to other North American countries and the development of its unconventional shale gas resources is proceeding slowly. Mexico habitually exports relatively small amounts of gas to the USA and imports considerably larger quantities. The country imported 499 Bcf of natural gas from the United States in 2011, which represented an increase of nearly 50 % from the levels of 2010. The United States also imports a very small amount of natural gas from Mexico, but the trade balance is expected to tip even further in the direction of the United States as recent supply and demand trends in both countries are projected to continue.

PEMEX has a monopoly on natural gas exploration. However, private participation is permitted in non-associated gas production. Production of natural gas has been rising since the turn of the century. According to statistics from Mexico's CNH, more than three-fifths of Mexico's natural gas production derived from associated oil and gas fields. Mexico produced an estimated 1.8 Tcf of dry natural gas in 2011, according to revised figures, which represents a slow rate of decline from the year before. Preliminary Mexican government data suggest that natural gas production has continued to fall in 2012.Regulatory bodies report that approximately 250 Bcf of natural gas was vented and flared in 2011. More than half of the country's venting and flaring occurred at Cantarell.

Mexico meets some of its natural gas demand through LNG, but the volume of its imports fell by roughly 20 % in 2011 as pipeline imports from the United States grew dramatically. According to data from the International Energy Agency, Mexico imported roughly 42 % of its LNG from Qatar, 28 % from Nigeria, and 16 % from Peru, and smaller volumes from Indonesia and other countries. The vast majority of Mexico's LNG imports — over 90 % in 2011 — arrive at the Altamira plant in Tamaulipas state, on Mexico's Northeastern coast. Altamira is a joint venture of Royal Dutch Shell (50 %), Total (25 %) and Mitsui (25 %).

PEMEX operates over 5,700 miles of natural gas pipelines in Mexico. The company has eleven natural gas processing centers, with liquids extraction capacity of 5.8 Bcf/d. PEMEX also operates most of the country's natural gas distribution network, which supplies processed natural gas to consumption centers.

The largest use of gas is as power generation fuel with 49% of the total. The energy industry consumed 26%, industrial fuel/feedstock 23%, and residential/commercial users about 2%. Mexican natural gas consumption is dominated by PEMEX operations and electricity demand. According to SENER statistics, PEMEX is the country's single largest consumer of natural gas, representing around 40 % of the country's total.

Myanmar

Proved recoverable reserves (bcm)	283.2
Production (bcm)	12.1
Consumption (bcm)	3.29
R/P ratio (years)	23.4

Myanmar has long been a small-scale producer of natural gas, but recent years have witnessed a substantial increase in its output, principally for export. There appear to be widely differing views on the level of its proved reserves. 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 plane.

In Asia-Pacific region, Myanmar stands as the second highest natural gas exporting country after Indonesia. In the fiscal year 2011-12, Myanmar fetched 3.56 billion U.S. dollars through export of gas, up about 640 million dollars from 2. 92 billion dollars in 2009-10 when the highest annual earning was gained with gas export. Natural gas export earned nearly 800 million U.S. dollars in first three months (April-June) of the fiscal year 2012-13.

Natural gas is one of Myanmar's largest sources of export revenue, accounting for about 30% of total exports. The exported gas was produced from the Yadanar and Yetagun gas fields, while other gas fields such as Shwe and Zawthika will start their production in 2013.

Statistics reveal that foreign investment in Myanmar's oil and gas sector had reached 13.815 billion U.S. dollars in 104 projects as of the end of November, 2011, accounting for 34.18 % of the total and standing the second in the country's foreign investment industries after electric power.

Namibia

Proved recoverable reserves (bcm)	62.29
Production (bcm)	0
Consumption (bcm)	0
R/P ratio (years)	0

The Namibian WEC Member Committee comments that the Kudu gas field discovered as long ago as 1974 had never been developed because of a lack of gas production and transport infrastructure. Recently licence-holders Tullow Kudu Ltd., CEICO E & P Co. Ltd. and the National Petroleum Corporation of Namibia (Pty) Ltd. have applied for a 25-year Production Licence based on the transport of the gas by CNG shuttle tankers to power plants and industrial gas markets in Namibia and South Africa.

In March 2010 it was reported that the Russian gas company Gazprom and the National Petroleum Corporation of Namibia (Namcor) were about to take a jointly-held 54% stake in the Kudu field, with Tullow's share being reduced from 70% to 31% and that of Japan's Itochu Corporation from 20% to 15%.

Namibia appears to have a greater potential for gas than for oil. Offshore exploration has identified some possible oil resources.

Netherlands

Proved recoverable reserves (bcm)	1303
Production (bcm)	81.09
Consumption (bcm)	54.08
R/P ratio (years)	16

The Netherlands have been producing gas for decades and its resource base has been in decline in recent years. There are over 400 proved natural gas accumulations in the Netherlands, both onshore and offshore. The remaining gas resources were estimated at 1.3 tcm. Of these remaining resources, the Groningen field accounted for 980 bcm, with 160 bcm to be found in other smaller onshore fields and 164 bcm in offshore formations.

In 2010 total production of natural gas in the Netherlands was over 85 bcm. The Groningen field is by far the largest source of Dutch gas production, and accounted for some 54 bcm of the 2010 total.

Domestic gas consumption in the Netherlands totalled some 54.8 bcm in 2010. Over a third of total gas use was consumed in the transformation sector. With some 96% of all households connected to gas supplies, the residential sector accounted for a substantial share, at 22% of the total, while the commercial and industry sectors each accounted for another 20% of gas use. Almost all space heating in the Netherlands is by natural gas, and over 60% of electricity is produced by gas fired generation, thus causing a strong seasonal pattern in gas use.

The Netherlands is the largest gas producer within the European Union. At the same time, the Netherlands imports and exports large volumes of gas, with roughly 40% of the total volume of gas flows used domestically. In 2010, the Netherlands exported 57.8 bcm of natural gas. The largest portion of these exports, 21.6 bcm, went to Germany while Belgium and the UK were the destinations of some 10 bcm each. Substantial volumes were also exported to Italy (8.7 bcm) and France (7.4 bcm). In the same year, the Netherlands imported nearly 25.8 bcm of gas, primarily from Norway, the UK and `Russia.

Based on the Dutch Administration's outlook for indigenous production and domestic use of natural gas, the Netherlands is expected to shift from being a net- exporter to being a net importer of gas in the period between 2020 and 2025.

Companies involved in Netherland's natural gas sector are Gasunie, GasTerra, Shell, Exxon, NEM, E.ON, DONG, Electrabel, Eneco, RWE, Vattenfall and Delta. GasTerra remains the major player in the wholesale market, with a share of between 70 and 75%. GasTerra is also very active on the European gas market, and has import contracts with suppliers from Russia, Norway and Germany.

New Zealand

Proved recoverable reserves (bcm)	27.64
Production (bcm)	4.36
Consumption (bcm)	4.27
R/P ratio (years)	6.33

Currently, all gas production in New Zealand takes place in the Taranaki basin. Early stage exploration is currently underway in the Canterbury, Great South, Northland, Deepwater Taranaki and Raukumara basins. The MED's Energy Outlook 2010 Reference Scenario predicts that by 2030 around one third of New Zealand's gas production will come from these frontier Basins.

The largest users of gas in New Zealand are Contact Energy and Genesis Energy for electricity generation. Electricity generation accounts for approximately 35 % of annual gas Demand.In New Zealand, 90 per cent of natural gas production comes from two gas fields: Maui (offshore) is mined by the Maui Mining Companies; and Kapuni (onshore) is mined by Shell and Todd. The remainder of the country's gas requirements come from a number of fields including the McKee, Kaimiro, Waihapa/Ngaere/Tariki/Ahuroa and Ngatoro fields.

Nigeria

Proved recoverable reserves (bcm)	5110
Production (bcm)	29
Consumption (bcm)	4.97
R/P ratio (years)	176.2

Nigeria had an estimated 180 trillion cubic feet (Tcf) of proved natural gas reserves as of the end of 2011, according to the OGJ, making Nigeria the ninth largest natural gas reserve holder in the world and the largest in Africa. Despite these vast natural gas reserves, Nigeria produced about 1 Tcf of dry natural gas in 2011 and ranked as the world's 25th largest natural gas producer only. The majority of the natural gas reserves are located in the Niger Delta and, therefore, the gas sector is also exposed to the same security and regulatory issues affecting the oil industry.

Shell dominates gas production in the country, as the Niger Delta, which contains most of Nigeria's gas resources, also houses most of Shell's hydrocarbon assets. The second largest gas producer is Total. Most of Nigeria's marketed natural gas is exported as Liquefied Natural Gas (LNG), with the remainder consumed domestically and exported regionally via the West African Gas Pipeline. Shell Nigeria Gas Limited (SNG), a Shell-owned gas sales and distribution company, also delivers Compressed Natural Gas (CNG) to industries as far as 62 miles away from existing pipelines.

In 2010, Nigeria exported 17.97 million metric tonnes (875 Bcf) of LNG, and became the fifth largest LNG exporter in the world and the largest LNG exporter in the Atlantic Basin. Furthermore, Nigeria's LNG accounted for 8% of the total supplied to the world market and 30% of LNG coming from the Atlantic Basin in 2010. Most of Nigeria's LNG was exported to Europe (67 %), mainly Spain (31 %), France (16 %) and Portugal (12 %), with smaller amounts to Turkey, United Kingdom, and Belgium. Other export destinations include Asia (15 %) and North America (14 %). The U.S. imported 0.86 million metric tonnes (42 Bcf) of Nigerian LNG in 2010, providing 1 % of total U.S. LNG imports.

Norway

Proved recoverable reserves (bcm)	2007
Production (bcm)	103.1
Consumption (bcm)	4.809
R/P ratio (years)	19.46

According to OGJ, Norway had 71 trillion cubic feet (Tcf) of proved natural gas reserves as of January 2012. Despite the aging of its major natural gas fields in the North Sea, Norway has been able to sustain annual increases in total natural gas production by continuing to develop new fields. Norway produced 3.64 Tcf of dry natural gas in 2011, down slightly from the 3.76 Tcf produced in 2010. Production has been generally increasing since 1993 and NPD forecasts it will reach 3.96 Tcf in 2015. Total gross natural gas production was 5.25 Tcf in 2011, of which 1.38 Tcf (26 %) was reinjected to enhance oil production. Norway's single largest natural gas field is Troll, which produced 0.9 Tcf in 2010, according to NPD, representing about one-quarter of Norway's total natural gas production. The three other largest producing fields in 2010 were Ormen Lange (0.7 Tcf), Asgard (0.4 Tcf), and Sleipner Ost (0.3 Tcf). These 4 fields accounted for about 60 % of Norway's total natural gas production.

Norway exported an estimated 3.5 Tcf of natural gas in 2011, 96 % of its production, according to NPD. Most of it was transported to Europe via its extensive export pipeline infrastructure and a smaller amount (4.3 %) via LNG tanker. The country is the second-largest supplier of natural gas to the European Union, behind Russia, supplying about 18 % of Europe's total gas demand in 2010 and ranks fourth in world natural gas production. The largest outlets for Norway's natural gas pipeline exports in 2010 were Germany, the United Kingdom, France, the Netherlands, and Belgium. According to NPD estimates, 2011 shipments of Norwegian LNG totaled an estimated 150 Bcf, up from 138 Bcf in 2010. OECD European countries in 2010 received about 74 % of the total, with Spain importing almost half of that. The United States imported about 5 % or 26.8 Bcf. Norway has long-term contracts with Spain's Iberderola and the U.S.'s El Paso.

As is the case with the oil sector, Statoil dominates natural gas production in Norway. A number of international oil and gas companies, including ExxonMobil, ConocoPhillips, Total, Shell, and Eni have a sizable presence in the natural gas and oil sectors in partnership with Statoil. State-owned Gassco is responsible for administering the natural gas pipeline network.

Oman

Proved recoverable reserves (bcm)	849.5
Production (bcm)	27.1
Consumption (bcm)	17.52
R/P ratio (years)	31.34

Oman is one of the smaller gas producers in the Middle East. Its proved reserves of natural gas are 30 trillion cubic feet (Tcf) as of January 2012, according to OGJ. Due to increasing EOR applications, rising domestic demand, and export obligations, Oman's gas demand has outpaced its production. Oman produced over one trillion cubic feet (Tcf) of natural gas, equal to about 2.75 billion cubic feet per day (Bcf/d) in 2011. Natural gas production has more than doubled in the past decade.

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 industrial consumers include mining and cement companies.

The Oman Gas Company (OGC) runs the country's natural gas transmission and distribution systems. The OGC is a joint venture between the Omani Ministry of Oil and Gas (80%) and OOC (20%). Oman Liquefied Natural Gas (OLNG)- owned by a consortium including the government, Shell and Total- operates all LNG activities in the Sultanate through its three liquefaction trains in Qalhat near Sur. Although Oman is a net exporter of oil and natural gas, it also imports small volumes of natural gas from Qatar via UAE. The Dolphin Pipeline provides Oman's only natural gas imports, providing approximately 200 million cubic feet per day (Mcf/d).

The pipeline system in Oman consists of 1,250 miles of pipeline, transporting natural gas supplies from production facilities primarily to gas-powered electric plants, participants in the petrochemical and industrial sectors, as well as to the Oman and Qalhat LNG projects. In 2015-16, OGC will add a 143-mile, 36-inch gas pipeline from Saih Nihayda field in Central Oman to service the special economic zone in Duqm on the east coast.

The Oman and Qalhat LNG projects are the sole source of natural gas exports from Oman, with a nameplate capacity of 506 Bcf per year, a daily average of 1.4 Bcf/d. In 2010, Oman exported a total of 406 Bcf, a decline of 2 Bcf from the previous year. Despite facing a gas shortage and increasing domestic demand, Oman exports 55 % of its gas because of term contracts, the first of which expires in 2020. Given shortfalls in natural gas production, in 2007 Oman began to import natural gas. The Dolphin Pipeline system, which transports 2 billion cubic feet per day (Bcf/d) of natural gas from Qatar to neighbouring UAE and eventually to Oman by way of the Fujairah - al-Ain pipeline, provides increasing natural gas supplies, around 200 Mcf/d, for use in electricity generation

Oman requires increased natural gas supplies to meet the growth in its domestic consumption as well as its enhanced oil recovery projects and LNG export obligations

Pakistan

Proved recoverable reserves (bcm)	753.8
Production (bcm)	42.9
Consumption (bcm)	42.9
R/P ratio (years)	17.57

Although the level of proved reserves reported by the Pakistan WEC Member Committee has tended to drift downwards in recent years, natural gas remains an important energy asset for Pakistan. Major gas-producing fields include Sui in Balochistan and Qadirpur, Mari, Zamzama, Sawan and Bhit in Sindh. Less than 2% of natural gas output was associated with oil production in 2008-09. Indigenous natural gas is the largest source of energy supply in Pakistan. Consumption of indigenous natural gas has grown rapidly in all sectors of the economy over the past 15 years, driven by growing availability of gas and a low, government-controlled gas price as compared with alternate fuel prices. The major domestic markets for gas (excluding own use) in that year were power generation (32%), industrial users (26%), fertiliser plants (16%), households and commercial consumers (20%) and fertiliser plants (16%). Rapidly growing quantities of CNG are consumed as an automotive fuel. Pakistan's state-owned PPL and OGDCL produce around 30 % and 25 %, respectively, of the country's natural gas. The two companies are the country's largest natural gas producers. OMV is the largest foreign natural gas producer (17 % of total country's production) in Pakistan. Other foreign operators include BP, Eni, and BHP Billiton. In addition to natural gas import pipelines, Pakistan is pursuing LNG import options to meet energy needs.

Papua New Guinea

Proved recoverable reserves (bcm)	155.3
Production (bcm)	110
Consumption (bcm)	110
R/P ratio (years)	1.41

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. 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 LNG project, which is planned to start producing 6.6 million tonnes of LNG from 2014, is moving ahead, with the project operator ExxonMobil stating in March 2010 that all financing arrangements were complete.

Peru

Proved recoverable reserves (bcm)	352.8
Production (bcm)	31.12
Consumption (bcm)	5.41
R/P ratio (years)	11.33

According to the Oil and Gas Journal, Peru had proved natural gas reserves of 12.5 trillion cubic feet (Tcf) in 2012, the fifth largest reserves in South America. Peru's main natural gas reserve is the large Camisea project in southeast Peru. Since production began in 2004, Camisea output has grown by an average of 37 % per year, and it is expected that when site exploration is complete, Peru's proved reserves will be up by another 318 billion cubic feet (Bcf).

Peru began exporting LNG from its Melchorita plant, South America's first natural gas liquefaction plant, in June 2010. In February 2012, Peru exported 15 Bcf (307,580 metric tons) of LNG according to LNG World News. Melchorita is owned by the PeruLNG consortium, made up of Hunt Oil at 50 %, SK Energy at 20 %, Repsol at 20 %, and Marubeni at 10 %. The plant currently has capacity of 215 Bcf per year, and a second and possibly a third train are planned to be added within the next four to five years. According to Cedigaz, in 2010, Peru shipped LNG cargoes to Spain, the United States, Mexico, China and South Korea. However, the majority of its exports are contracted to go to the LNG terminal in Manzanillo, Mexico. Although the Manzanillo terminal and 186-mile pipeline were completed in September 2011, the need to dredge the harbour for shipping delayed the project until March 2012. The first cargo of LNG was shipped to Manzanillo on March 10, 2012. There are two pipelines carrying natural gas from the Camisea gas fields. The 336-mile Camisea pipeline terminates at the Pisco port terminal, from which liquefied petroleum gases (LPG) are exported. A second 444-mile pipeline runs from Malvinas along the coast to Lima and Callao for distribution to residential and industrial consumers in the capital city. The pipelines are owned by TGP. The distribution of natural gas through pipelines within Peru is controlled by the private consortium Transportadora de Gas Peruano (TGP), made up of Tecgas, Pluspetrol, Hunt Oil, SK Corp, Sonatrach, and Grana y Montero. Spain's Repsol, South Korea's SK Corp, Italy's Tecpetrol, and Algeria's Sonatrach. Pluspetrol operates the natural gas wells at Camisea, making it the largest hydrocarbons producer in the country.

Qatar

Proved recoverable reserves (bcm)	25200
Production (bcm)	116.7
Consumption (bcm)	21.8
R/P ratio (years)	215.9

Qatar controls 14% (over 25 trillion m3) of the total world natural-gas reserves, which makes it the third country in the world in terms of the proved gas reserves only behind Russia and Iran. Today, Qatar is the single largest supplier LNG. The majority of Qatar's natural gas is located in the massive offshore North Field, which spans an area roughly equivalent to Qatar itself.

In 2011, Qatar exported over 117.6 Bcm of natural gas, of which over 80% was LNG primarily to Asia and Europe. The United States received 2.52 Bcm of Qatar's LNG, which represented 26% of total U.S. imports of LNG in 2011. The remaining exports (19.04 Bcm) of natural gas were transferred through the Dolphin pipeline to the United Arab Emirates (UAE) and Oman.

Qatar is the world's leading LNG exporter. In 2011, Qatar exported nearly 100.8 Bcm of LNG. The United Kingdom, Japan, India, and South Korea were the primary destinations for Qatar's LNG exports. Asia was the principal import hub, accounting for 48% of Qatar's LNG in 2011. European markets, including Belgium, the United Kingdom, and Spain were also significant buyers of Qatari LNG, accounting for an additional 42%.

Qatar's LNG sector is dominated by Qatargas Operating Company Limited (Qatargas), which operates four major LNG ventures (Qatargas I-IV).

Companies involved in Qatar natural gas are ExxonMobil, Shell, and Total, Qatar petroleum (QP), Qatargas.

Romania

Proved recoverable reserves (bcm)	63
Production (bcm)	10.59
Consumption (bcm)	12.87
R/P ratio (years)	5.95

After peaking in the mid-1980s, Romania's natural gas output has been in gradual secular decline, falling to around 11 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.

Romania has proved natural gas reserves of 726 billion cubic meters (25.94 trillion cubic feet) and is ranked 30th among countries with proved reserves of natural gas. About 75% of Romania's natural gas resources are located in Transylvania, especially in Mure- and Sibiu counties. The largest natural gas field in Romania is the Deleni gas field discovered in 1912 and located in the B-gaciu commune in Mure- County with proved reserves of 85 billion cubic meters or 3 trillion cubic feet.

The local natural gas production is dominated by two very large companies Romgaz with a market share of 51.25% and Petrom with a market share of 46.33%. There are also several smaller companies Aurelian Oil&Gas with a market share of 0.38%, Amromcowith a market share of 1.85%, Lotus Petrol with a market share of 0.13% and Wintershall with a market share of 0.06%.

The national natural gas transmission system in Romania is owned by Transgaz a state-owned company. It has a total network length of 13,110 km (8,150 mi) of pipelines with diameters between 50 mm (2.0 in) and 1,200 mm (47 in). The company also owns a 50% stake in the Arad–Szeged pipeline, a natural gas pipeline from Arad in Romania toSzeged in Hungary, with a length of 109 km (68 mi) and a transport capacity of 4.4 billion cubic meters (0.15 Tcf) per year.Romania also has four other pipeline links to Ukraine used for the import or transit of natural gas.

Russian Federation

Proved recoverable reserves (bcm)	47570
Production (bcm)	669.6
Consumption (bcm)	506.7
R/P ratio (years)	71.1

Russia holds the largest natural gas reserves in the world, and is the largest producer and exporter of dry natural gas. The majority of these reserves are located in Siberia, with the Yamburg, Urengoy, and Medvezh'ye fields alone accounting for about 45 % of Russia's total reserves. In 2011 Russia was the world's largest dry natural gas producer (23.6 Tcf), regaining its status as the world top producer after trailing U.S. production in 2009 and 2010. Russia is also the world's largest exporter (7.2 Tcf).

The state-run Gazprom dominates Russia's upstream, producing about 80 % of Russia's total natural gas output. Gazprom also controls most of Russia's gas reserves, with more than 65 % of proved reserves being directly controlled by the company and additional reserves being controlled by Gazprom in joint ventures with other companies.

Natural gas associated with oil production is often flared. According to the U.S. National Oceanic and Atmospheric Administration, Russia flared an estimated 1,244 Bcf of natural gas in 2010, the most of any country in the world. At this level, Russia alone accounted for about 30 % of total volumes of gas flared globally in 2010. The Russian government has taken steps to reduce natural gas flaring and set a target of 95 % utilization of associated gas by the end of 2012. However, given current the volume of gas flared, it is unlikely companies will achieve this target.

Russia exports significant amounts of natural gas to customers in the Commonwealth of Independent States (CIS) – about 35 % of total exports. In addition, Gazprom (through its subsidiary Gazexport) has shifted much of its natural gas exports to serve the rising demand in countries of the EU, as well as Turkey, Japan, and other Asian countries. About 70 % of Russia's non-CIS exported natural gas is destined for Europe, with Germany, Turkey, and Italy receiving the bulk of these volumes. The remainder of Russia's European gas exports are sold to the newest EU members such as Czech Republic, Poland, and Slovakia.

In addition to dominating the upstream, Gazprom dominates Russia's natural gas pipeline system. There are currently nine major pipelines in Russia, seven of which are export pipelines. The Yamal-Europe I, Northern Lights, Soyuz, and Bratrstvo pipelines all carry Russian gas to Eastern and Western European markets via Ukraine and/or Belarus. These four pipelines have a combined capacity of 4 Tcf. Three other pipelines – Blue Stream, North Caucasus, and Mozdok-Gazi-Magomed – connect Russia's production areas to consumers in Turkey and Former Soviet Union (FSU) republics in the east.

Russia is an exporter of liquefied natural gas (LNG). The majority of the LNG has been contracted to Japanese and Korean buyers under long-term supply agreements. In 2011, Sakhalin LNG exports went to Japan (69.5 %), South Korea (25.7 %), China (2.4 %), Taiwan (1.7 %), and Thailand (0.6 %). The Sakhalin Energy's LNG plant has been operating since 2009 and it can export up to 10 million tons of LNG per year on two trains.

There are a number of proposals in various stages of planning and construction for new LNG terminals in Russia, including: Yamal LNG, Shtokman LNG, Vladivostok.

Saudi Arabia

Proved recoverable reserves (bcm)	8028
Production (bcm)	99.23
Consumption (bcm)	99.23
R/P ratio (years)	80.9

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 rank as the third largest in the Middle East. Other published sources' assessments are generally similar.

Output of natural gas has advanced fairly steadily for more than a quarter of a century. A significant factor in increasing Saudi Arabia's utilisation of its 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.

Saudi Arabia has the world's fifth largest natural gas reserves, but natural gas production remains limited. Its proved natural gas reserves of 288 trillion cubic feet (Tcf) at the end of 2012, are fifth largest in the world behind Russia, Iran, Qatar, and the United States, according to EIA estimates. About 5 Tcf was added in 2012, and over the last decade, Saudi Arabia added over 60 Tcf of natural gas reserves.

The majority of gas fields in Saudi Arabia are associated with petroleum deposits, or found in the same wells as the crude oil, and production increases of this type of gas remain linked to an increase in oil production. About 57 % of Saudi Arabia's proved natural gas reserves consists of associated gas at the giant onshore Ghawar field and the offshore Safaniya and Zuluf fields.

Saudi Arabia does not import or export natural gas, so all consumption must be met by domestic production. According to Saudi Aramco forecasts, natural gas demand in the Kingdom is expected to almost double by 2030 from 2011 levels of 3.5 trillion cubic feet (Tcf) per year.

- Saudi Arabia has four upstream joint ventures in the Empty Quarter:
- South Rub al-Khali Company or SRAK (a venture of Saudi Aramco and Royal Dutch Shell)
- Luksar Energy Limited (a venture of Saudi Aramco and Lukoil)
- Sino Saudi Gas Limited (a venture of Saudi Aramco and Sinopec)
- EniRepSa Gas Limited (a consortium of Saudi Aramco, Eni, and Repsol-YPF)

Domestic demand for natural gas, particularly the delivery feedstock to petrochemical plants, has driven consistent expansion of the Master Gas System (MGS), the domestic gas distribution network in Saudi Arabia first built in 1975. Prior to the MGS, all of Saudi Arabia's natural gas output was flared. The MGS feeds gas to the industrial cities including Yanbu on the Red Sea and Jubail.

Thailand

Proved recoverable reserves (bcm)	299.8
Production (bcm)	36.27
Consumption (bcm)	45.08
R/P ratio (years)	8.26

Since its inception nearly 30 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.

PTTEP has a stake in many of Thailand's natural gas producing fields, including Bongkot, the largest field. The largest foreign operator is Chevron, which currently accounts for 70 % of Thailand's natural gas production from 22 offshore fields. Several projects are currently being developed in an attempt to increase Thailand's natural gas supplies over the next few years. The largest of these is PTTEP's Arthit project, off the coast of Songkhla. The country has been able to attract several major international companies to its concessions, most notably Chevron, Mitsui Oil Exploration and Hess. Chevron is the biggest operator in Thailand followed by PTTEP the national oil & gas company.

Thailand has one LNG Import Terminal, the Map Ta Phut Thailand Lng Terminal, belonging to PTTEP, which was commissioned in 2011.

Trinidad & Tobago

Proved recoverable reserves (bcm)	381.8
Production (bcm)	42.46
Consumption (bcm)	22.08
R/P ratio (years)	8.99

In the span of only five years, proved natural gas reserves have declined sharply by over 50 %, from 25.9 Tcf in 2006 to 14.4 Tcf in 2011, according to Oil & Gas Journal as of January 1, 2012. According to PFC Energy, the country may not be able to sustain current output levels through the end of the decade.

Natural gas production currently accounts for just over 85 % of the country's natural resource base. The construction of the country's first LNG train in the 1990s and its completion in 1999 facilitated the increase in natural gas production.

In 2010, the country produced 1.5 trillion cubic feet (Tcf) of natural gas, over three times the level seen in 2000. Domestic consumption of natural gas has steadily increased as well, as domestic demand is supported by government subsidies. Consumption grew to 780 billion cubic feet (Bcf) in 2010, just over double the level at the start of the decade.

The country has benefited from substantial foreign investments, with BP Trinidad and Tobago (BPTT) accounting for almost 60 % of the country's natural gas production. British Gas is the second leading player in the industry, operating nearly a quarter of the natural gas production in the country. National companies participate in the sector as small shareholders in operations

Trinidad and Tobago is the largest supplier of LNG to the United States, and the fifth largest exporter in the world after Qatar, Indonesia, Malaysia, and Australia, according to FACTS Global Energy 2010 figures. EIA data shows that Trinidad and Tobago exported 129 Bcf of natural gas to the United States in 2011, about 37 % of total U.S. LNG net imports, but less than 1 % of total U.S. natural gas supply. In the last five years, U.S. LNG imports from Trindad and Tobago have declined by almost one-third, which reflects the general decline in total U.S. LNG imports.

The Atlantic LNG Company, a consortium led by BP, BG, GDF Suez, and the former Repsol-YPF, operates four LNG trains at Point Fortin, on the south-western coast of Trinidad.

Turkmenistan

Proved recoverable reserves (bcm)	75.04
Production (bcm)	45.3
Consumption (bcm)	20.4
R/P ratio (years)	165.65

Turkmenistan currently ranks in the top six countries for natural gas reserves and the top 20 in terms of gas production. According to OGJ, Turkmenistan has proved natural gas reserves of approximately 265 Trillion cubic feet (Tcf) in 2012, a significant increase from 94 Tcf estimated in 2009. Turkmenistan has several of the world's largest gas fields, including 10 with over 3.5 Tcf of reserves located primarily in the Amu Darya basin in the southeast, the Murgab Basin, and the South Caspian basin in the west. Recent major discoveries at South Yolotan in the prolific eastern part of the country are expected to offset most declines in other large, mature gas fields and will likely add to the current proved reserve amounts.

The country's consumption of total primary energy reached 1 quadrillion Btu. Of this amount, approximately 78 % (0.78 quadrillion Btu) was from natural gas. All of Turkmenistan's power generation facilities are gas-fired.

A majority of Turkmen gas travels to Russia where it is consumed or transits through Russia to end markets in Europe. In November 2010, Turkmenistan's Ministry of Oil, Gas, and Mineral Resources said the country's energy strategy is to more than triple gas production to over 8.1 Tcf/y by 2030.

The Dauletabad field, located in the Amu Darya basin in the southeast, is one of Turkmenistan's largest and oldest gas-producing fields with estimated reserves of 60 Tcf. The field produced approximately 1.2 Tcf/y in 2010 or most of Turkmenistan's gas supply, however, production is declining. Turkmenistan has become a leading gas exporter in the Caspian and Central Asian region. The country exports a majority of its gas because production rates are more than double domestic demand estimated at 720 Bcf/y in 2010. The International Energy Agency assumes exports will rebound and rise to about 3,180 Bcf/y by 2035.

Two pipelines to Iran and China began operations recently, and other routes are under consideration. Maximum existing gas export capacity from Turkmenistan is now close to 3,500 Bcf/y.

Other major pipelines are: Central Asia Center Pipeline (CAC, Korpezhe-Kurt Kui Pipeline (Turkmenistan to Iran), Dauletabad-Khangiran Pipeline (Turkmenistan to Iran), Central Asia-China Pipeline (Turkmenistan to China), Bukhara-Urals Pipeline, East-West Pipeline, Turkmenistan-Afghanistan-Pakistan-India Pipeline (TAPI), Trans-Caspian Pipeline (TCGP).

Ukraine

Proved recoverable reserves (bcm)	1104
Production (bcm)	19.36
Consumption (bcm)	53.16
R/P ratio (years)	57

Ukraine's output of natural gas has been virtually flat since 1994, although production since 2003 has been 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 75 bcm by 2008, indigenous production met only 26% of local needs; the balance was imported from Russia and Turkmenistan. The consumption of gas is spread fairly evenly over electricity and heat plants, industrial fuel and feedstocks, and the tertiary sector.

Ukraine is a key transit center for Russian natural gas exports to Europe. In order to provide reliable supplies domestically and in Europe more investment in the Ukrainian transport network, more international cooperation, and a more transparent energy sector are needed.

In 2010, Ukraine consumed 2,034.1 BCF (57.6 bn. m3) of natural gas, an increase of 11.0% since 2009, and 72.6 MMboe of crude oil (an increase of 2.7% over 2009).

Despite this Ukraine still has to import about 80% of its natural gas needs, mainly from Turkmenistan and Russia (about two-thirds of its gas in 2012).

United Arab Emirates /UAE

Proved recoverable reserves (bcm)	60.89
Production (bcm)	51.28
Consumption (bcm)	60.54
R/P ratio (years)	118.74

The proved reserves of 215 Tcf of natural gas in the UAE are located almost entirely in Abu Dhabi, as that emirate controls approximately 94 % of the country's endowment with an estimated 201.7 Tcf in 2011. Sharjah has the second-highest volume of proved reserves (8.65 Tcf), followed by Dubai (3.53 Tcf) and Ras al-Khaimah (1.06 Tcf). Production in the UAE is also dominated by Abu Dhabi, with reported gross production of 2.42 Tcf in 2011 far outstripping the other emirates combined (491 billion cubic feet).

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.

Rapid growth in domestic energy demand over the past few years has caused the UAE to become a net-importer of natural gas.

Beyond its vast oil reserves, the UAE has 215 trillion cubic feet (Tcf) of proved natural gas reserves, ranking it seventh in the world, according to Cedigaz. The UAE is not as prolific a producer of natural gas as it is of oil, nevertheless it was the 11th-largest producer of natural gas in the world in 2011 (2.91 Tcf). Despite its large endowment, the UAE became a net importer of natural gas earlier this decade.

To help meet the growing demand for natural gas, the UAE boosted imports from neighbouring Qatar via the Dolphin Gas Project's export pipeline. The pipeline runs from Qatar to Oman via the UAE, and is one of the principal points of entry for UAE natural gas imports.

Most of the UAE's natural gas has relatively high sulphur content, making the development and processing of the country's vast reserves economically challenging. Because of this, nearly 30 % of UAE's gross production of more than 2.91 Tcf is re-injected into oilfields as part of the nation's EOR techniques; marketed production in 2011 was just 1.85 Tcf, placing the UAE 17th in the world.

The UAE's total gross production of 2.91 Tcf in 2011 ranked 11th in the world, but its marketed production was almost 40 % lower at just 1.85 Tcf (17th in the world in 2011). Most of this difference is attributable to the UAE's extensive—and increasing—use of enhanced recovery techniques, though the country continues to engage in a small amount of flaring.

Most of the UAE's domestically-produced and imported gas is used in the country's extensive EOR operations and to operate their numerous power plants and de-salinization plants.

Several recent and ongoing projects—the Onshore Gas Development (OGD), Integrated Gas Development (IGD), and Offshore Associated Gas (OAG) projects—seek to boost production of the country's reserves, and are intended to help meet the rapidly-growing demand for natural gas in the country.

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 2008, Abu Dhabi's other LNG customer was India.

Within the UAE, gas is used mainly for electricity generation/desalination, and in plants producing aluminium, cement, fertilisers and chemicals

In 2011, total natural gas imports amounted to 616 Bcf, with 300 Bcf going to Abu Dhabi, 298 Bcf to Dubai, and small amounts to the other Emirates. The UAE received nearly 97 % of its natural gas imports from neighbouring Qatar, with 95 % coming via pipeline and the remaining 5 % in the form of LNG shipments to Dubai.

Major companies involved in United Arab Emirates natural gas are: ADNOC, ADCO, ADMA-OPCO, GASCO, shel, total, partex, ADGAS, DUGAS.

Early in 2012, the UAE announced plans to add a second re-gasification terminal—Emirates LNG—offshore at Fujairah, with an initial capacity of 600 MMcf/d and the potential for expansion to 1.2 Bcf/d. The project will help the country meet its growing demand for natural gas, and should be operational in late 2014.

United Kingdom

Proved recoverable reserves (bcm)	253
Production (bcm)	47.43
Consumption (bcm)	81.21
R/P ratio (years)	5.33

According to OGJ, the U.K. held an estimated 9 trillion cubic feet (Tcf) of proved natural gas reserves in 2011, a 12 % decline from the previous year. Most of these reserves occur in three distinct areas: 1) associated fields in the U.K. continental shelf (UKCS); 2) non-associated fields in the Southern Gas Basin, located adjacent to the Dutch sector of the North Sea; and 3) non-associated fields in the Irish Sea The U.K. produced 2.0 Tcf of natural gas in 2010, falling about 5 % compared with the previous year, which was a significantly smaller decrease than last year's 15 %. At 2.0 Tcf, U.K.'s production reached its lowest level since 1992. The largest concentration of natural gas production in the U.K. is the Shearwater-Elgin area of the Southern Gas Basin.

Currently, the U.K. has four LNG import terminals and the country was the eighth-largest importer of LNG in 2010. The longest-operating LNG terminal in the U.K. is National Grid's Grain LNG terminal on the Isle of Grain. U.K. received 55 % of its LNG imports from Qatar in 2009, with the remaining volumes arriving from Trinidad and Tobago, Algeria, Egypt, and Australia. In addition, a tanker carrying the first-ever shipment of LNG from the U.S. to the U.K. arrived on the U.K. shores in November 2010.

Private companies control the U.K. natural gas sector, including production, distribution, and transmission. The largest gas distributor in the UK is Centrica, a spin-off of the distribution assets of formally state-owned British Gas.

Most of the leading oil companies in the U.K. are also the leading natural gas producers, including BP, Shell, and ConocoPhillips. The major gas distribution companies in the U.K., such as BG Group and E.ON Ruhrgas, also have a presence in the production sector.

United States of America

Proved recoverable reserves (bcm)	77.16
Production (bcm)	651.3
Consumption (bcm)	689.9
R/P ratio (years)	11.84

The USA possesses the world's fifth largest proved reserves of natural gas, and accounts for almost 4% of the global total. US natural gas proved reserves are now at their highest level since the EIA began reporting them in 1977. Their growth in recent years is largely attributable to the continued development of unconventional gas from shales, reflecting the oil industry's successful application of horizontal drilling and hydraulic fracturing to shale formations. In 2008, proved reserves of shale gas grew by over 50% and by year-end constituted 13.4% of total US proved reserves of natural gas. Two-thirds of the USA's proved shale gas reserves are located in Texas.

The states with the largest gas reserves at end-2008 were Texas (31.7% of the USA total), Wyoming (12.7%), Colorado (9.5%) and Oklahoma (8.5%). Reserves in the Federal Offshore areas in the Gulf of Mexico accounted for 5.5% of the total. About 89% of proved reserves consist of non-associated gas.

Uzbekistan

Proved recoverable reserves (bcm)	1745
Production (bcm)	63.4
Consumption (bcm)	4.1
R/P ratio (years)	7.3

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.

Uzbekistan is a major producer of natural gas, greater than, for example, Egypt or the UAE. 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)	5524
Production (bcm)	31.2
Consumption (bcm)	33.1
R/P ratio (years)	177

According to OGJ, Venezuela had 195 trillion cubic feet (Tcf) of proved natural gas reserves in 2012, the second largest in the Western Hemisphere behind the United States. In 2011, the country produced 1.1 trillion cubic feet (Tcf) of dry natural gas, while consuming nearly 1.2 Tcf. The petroleum industry consumes the majority of Venezuela's gross natural gas production, with the largest share of that consumption in the form of gas re-injection to aid crude oil extraction. Due to the declining output of mature oil fields, natural gas use for enhanced oil recovery has increased by more than 50 % since 2005. An estimated 90 % of Venezuela's natural gas reserves are associated.

PdVSA produces the largest amount of natural gas in Venezuela, and it is also the largest natural gas distributor. A number of private companies also currently operate in Venezuela's gas sector. Participants with significant assets include Repsol-YPF, Chevron, and Statoil.

In recent years, Venezuela has improved its 2,750 mile domestic natural gas transport network to allow greater domestic utilization and movement of natural gas production with the roughly 190 mile Interconnection Centro Occidente (ICO) system. The ICO connects the Eastern and Western parts of the country, making natural gas more easily available for domestic consumers and for re-injection into western oil fields. Upon its expected completion in late 2012, the ICO will have a capacity of 520 million cubic feet per day (MMcf/d). In addition, the 300 mile SinorGas pipeline project will transport gas produced offshore to the domestic pipeline network via Sucre and Anzoategui. To meet the growing industrial demand, Venezuela imports gas from Colombia and the United States.

Venezuela has by far the biggest natural gas resources in South America and possesses more than two-thirds of regional proved reserves. Substantial quantities of Venezuela's natural gas (amounting to almost 45% of gross output in 2008) are re-injected in order to boost or maintain reservoir pressures, while smaller amounts (12%) are vented or flared; about 10% 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)	478.5
Production (bcm)	6.24
Consumption (bcm)	0.76
R/P ratio (years)	**76.6**

According to the Oil & Gas Journal, as of January 1, 2012, Yemen had 16.9 trillion cubic feet (Tcf) of proved natural gas reserves. Most of Yemen's natural gas reserves are associated gas concentrated in the Marib-Jawf oil fields, which contain 10 Tcf of proven natural gas reserves.

In 2010, Yemen produced an estimated 1,153 billion cubic feet (Bcf) of gross natural gas, of which 890 Bcf was reinjected to provide enhanced oil recovery and 245 Bcf was marketed, including 194 Bcf exported as LNG.

A long-term LNG sales contract with Korea Gas Corporation was signed in 2005, providing the impetus and the investment needed to begin development of the country's natural gas reserves. Contracts were also signed with GDF Suez and Total. All three contracts run for 20 years.

According to Cedigaz estimates, Yemen exported a total of 194 Bcf of LNG in 2010. The principal buyers were South Korea (38 %), the United States (20 %), and China (13 %).

Yemen LNG is the largest industrial project in the country. French company Total holds a 39.6 % stake in the project, followed by Hunt Oil at 17.2 %, Yemen Gas Company at 16.7 %, and 3 South Korean companies - SK Gas at 9.55 %, KoGas at 6 %, and Hyundai at 5.88 % - while other Yemeni investors make up the balance reserves. A long-term LNG sales contract with Korea Gas Corporation was signed in 2005, providing the impetus and the investment needed to begin development of the country's natural gas reserves. Contracts were also signed with GDF Suez and Total. All three contracts run for 20 years.

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Unconventional gas

There are four main categories of unconventional natural gas: shale gas, coalbed methane, gas from tight sandstones (‘tight gas’) and the least well-known methane hydrates.

1. Shale Gas

Today, shale gas is making headlines all over the world. Therefore, this 2013 edition of the World Energy Resources has a special extended feature on shale gas which has effectively revolutionised the gas industry, especially in North America. In its quest for clean, secure, sustainable and affordable supplies of energy, the world is turning its attention to “unconventional” and “new” promising energy resources.

Shale gas is not a “new” energy resource. The first commercial gas well in the USA, drilled in New York State in 1821 was in fact a shale gas well. Over the years, limited amounts of gas were produced from shale formations, until the recent “Shale Gas Revolution” changed the natural gas scene, first in the United States and subsequently in other countries around the globe. This radical transformation occurred in recent years due to the development of a new application of “fracking” technology

Emerging Shale Gas Plays

There are nearly 700 known shales worldwide in more than 150 basins. At present, only a few dozen of these shales have properly assessed production potentials, most of those are in North America. The potential volumes of shale gas are enormous and this is likely to reshape significantly the gas markets in Europe and LNG markets worldwide.

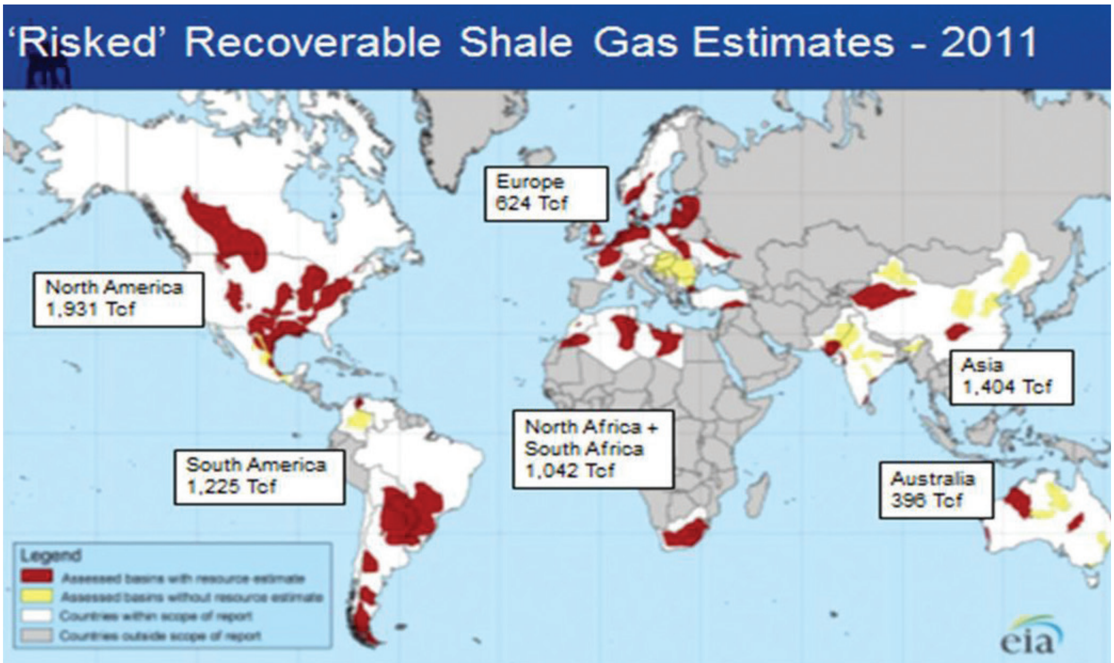
In about 30% of the identified basins there is existing infrastructure that could reduce capital expenditures related to exploitation of shale gas. However, even in these basins there is likely to be significant need for capital expenditures to process, store and distribute the gas through a pipeline system. The capital costs of developing that infrastructure will be considerable and may result in delaying new production from coming online or make the entire endeavour uneconomic. Although capital costs may be significant, shale formations may still be worth exploiting for both financial and strategic reasons.

Shale Gas Resource Base and Current Developments

Oil majors and other global companies are expanding their shale gas activities outside the United States. For example, ExxonMobil and Marathon Oil have launched shale gas operations in Poland, France, Germany, Sweden and Austria. It is believed that the total shale gas resource base is both large and wide-spread around the world. However, this potential resource has not yet been quantified on a national level in the majority of countries. The most credible studies put the global shale gas resource endowment at about 16,110 tcf (456 tcm). It is assumed that nearly 40% of this endowment would be eventually recoverable. The United States and the CIS countries together account for over 60% of the total estimate.

Estimated Shale Gas Potential (2011)

Source: WEC Shale Gas report 2010



European reserves, on the other hand, are not very impressive at slightly over 7% of the global reserves, and China and India on current estimates hardly reach a 2% share each.

It should be emphasised that these are best estimates available today and they can change significantly when proper assessments are performed. The US provides an enlightening case study. In 2007 US shale gas resource base was estimated at 21.7 tcf, and only a year later it jumped up to 32.8 tcf. At the end of 2008 shale gas accounted for 13.4% of US proved reserves of natural gas, compared with 9.1% at the end of 2007.

Approximately one half of the mentioned reserves are shale deposits, the rest are contained in coal seams and sandstone. Even if the current attention on shale turns out to be temporary, further development of natural gas infrastructure will be useful for other sources of natural gas. Further, the advancement of technology used to exploit shale gas will spur further technical advancements for other energy resources. An additional major challenge to developing shale plays will be the need for new or expanded pipeline infrastructure to transport gas.[1]

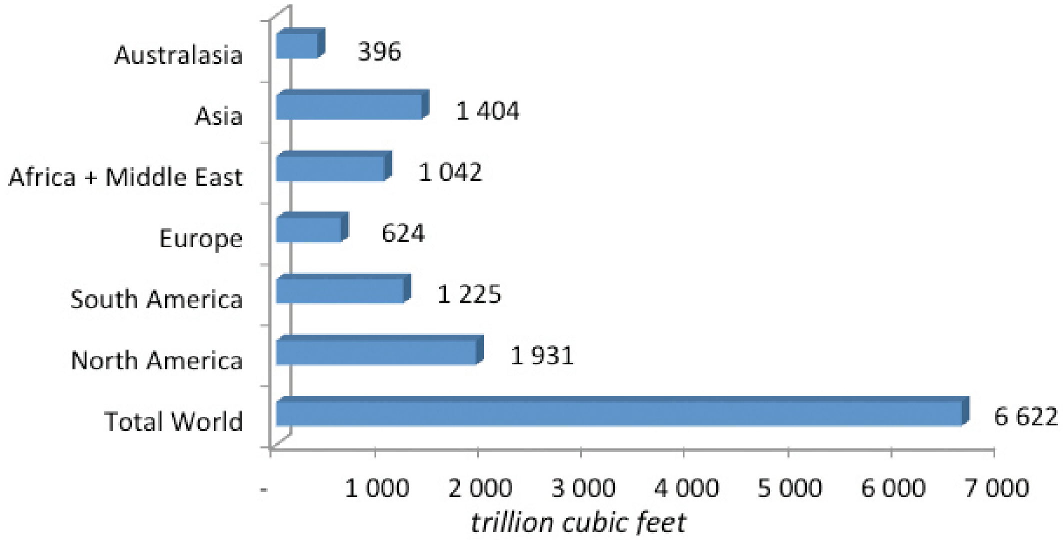
Countries and regions with large conventional gas reserves, like Russia and the Middle East, were not included in the study.

According to the US Department of Energy (DOE), their new estimates should be considered 'risked', which means that the methodology employed 'recognised the sparseness and uncertainty of data and included conservative discounting of the potential resource.' In other words, exploration activity has been sparse in many shale basins, which means that reliable seismic data is not yet available

1 Source: Survey of Energy Resources: Shale Gas – What's New, World Energy Council 2011

'Risked' recoverable Shale Gas reserves by region (2011)

Source: WEC Shale Gas 2011 report



Technologies

The recent advances in shale gas production technologies have been achieved largely by a combination of horizontal drilling with hydraulic fracturing. In this procedure, a well is sunk to a depth somewhat less than that of a known shale gas deposit and then gradually deviated until the drill-bit is running horizontally through the shale bed. Once drilling has been completed, the rock surrounding the horizontal bore is perforated in a number of places and artificial fracturing induced by the high-pressure injection of water combined with special additives and sand - called a proppant - to keep the fracture open. The other major technological improvement was horizontal drilling. The technique per se is not new and is practiced all over the world. The dramatic increase in production rates over vertical wells justified the higher cost of these wells. The majority of them are lined with a steel casing embedded in cement. Whether cased or not, most of the wells have what are known as multi-staged completions. This is a technology involving isolation of the productive zones and fracturing just those zones. Ten or more of these zones are not uncommon. Another technique is directing the well at an angle to the maximum horizontal stress to allow transverse fractures, which maximize production. All of this involves fairly sophisticated geophysical mapping of the rock.

Another new technique is pad drilling, where multiple wells are drilled and completed from a single location. This minimizes the need for roads and reduces the overall footprint of production, especially important in populated areas or farmland and other environmentally sensitive areas. It also allows for a higher level of sophistication in material handling.

While work on shale gas has, to date, been very largely concentrated in North America, and especially the USA, other parts of the world are now following suite, and preliminary resource assessments are being conducted in a number of countries and regions. For example, the ARI paper referred to above specifies three European basins as of particular importance – the Alum Shale in Sweden, the Silurian Shales in Poland and Austria's Mikulov Shale. Together, these basins are estimated to have a shale gas resource of around 1 000 tcf (roughly 30 tcm), of which about 140 tcf (4 tcm) is considered to be recoverable under present economic conditions.

Current Trends and Outlook

A considerable amount of exploration activity is being undertaken to establish the location of viable shale gas reservoirs, mostly by relatively small companies, in Australia, Austria, Canada, China, France, Germany, Hungary, India, New Zealand, Poland, South Africa, Sweden, United Kingdom and the United States.

A balanced view on shale gas

The emergence of shale gas as a potentially major source of energy has been accompanied by a flurry of publicity, both for and against further development of shale gas. The identified benefits of shale gas include:

- potentially enormous resource base;
- lower carbon emissions than from other fossil fuels;
- applicability of the technology throughout the world;
- improved diversity and security of supply for gas-importing countries;
- extension of the production in some existing gas fields and opening-up of new fields;

On the other hand, the drawbacks include:

- uncertainty over costs and affordability;
- questions about the environmental acceptability of the technology;
- poor reporting of decline rates;
- potential shortages of equipment;
- local opposition to shale gas development;

Economics and markets

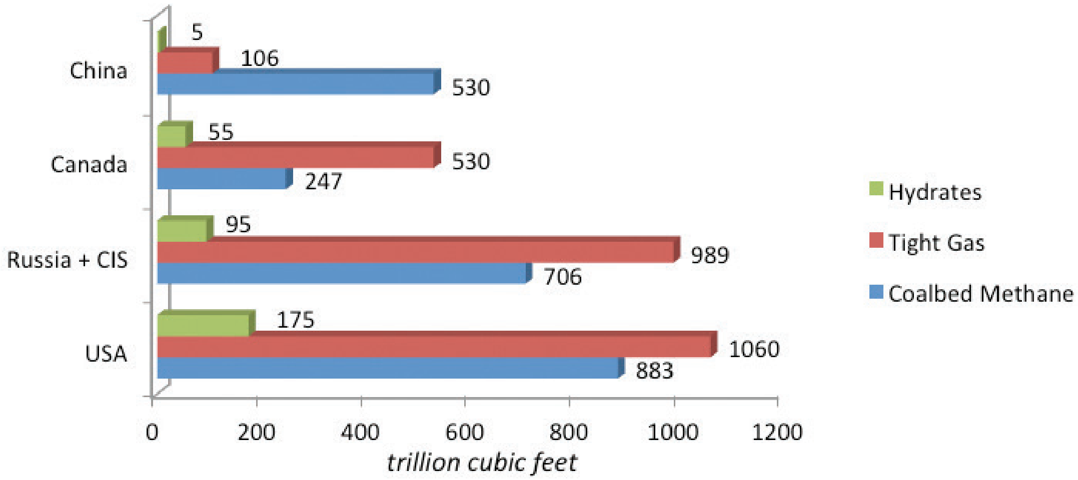
Large international oil companies (IOCs) seem to believe in the long-term economics of shale gas, as Exxon, Total, Shell, CNP, Reliance Industries and others have acquired significant stakes in shale gas resources in North America. These acquisitions, which will require further investments over a period of several years demonstrate the value the oil industry places on the future of shale gas. The increasing participation of oil majors in North American shale gas exploitation brings positive implications for the use of best practices and technologies in drilling and processing. Furthermore, the IOCs will most likely lead exploration activities worldwide.

Shale gas in China – A defining moment for the global energy sector

How much shale gas is there in China and other large emerging economies? A short and frank answer today would be that no one knows yet. However, the leading gas industry players agree that China's shale gas potential is large. US DOE/IEA recently estimated China's shale gas reserves at 1,275 tcf, which is more than the US and Canada's known reserves put together. Further exploration of China's shale gas potential will produce more reliable figures, but this will take some time. At the moment, no one knows with any degree of certainty where the Chinese shale plays are located and whether gas production would be commercially viable. So far, geological assessments have concluded that the most promising locations for shale gas deposits are in North-Western China (Tarim Basin), North-Central China (Ordos Basin) and South-West China (Sichuan Basin).

Recoverable Unconventional Gas reserves (2009)

Source: BGR Energierohstoffe 2009 report



The presence of large oil majors in China indicates that the industry believes in the shale gas future in China. If this assumption is true, shale gas would most certainly change the energy landscape in the country and in the entire world. China's economic growth has been spectacular, and it is set to continue for decades to come. Demand for electricity, for example, is expected to double within the next 20 years. The country is currently adding approximately 1,000MW of installed capacity per week, and over 90% of this capacity is coal-fired. 80% of China's electricity is generated by coal-fired power plants, and the country accounts for nearly 50% of the total coal consumption in the world. Given that coal-fired power plants are the largest emitters of Greenhouse Gases (GHG), the earlier China substitutes coal for shale gas, the lesser the environmental impact this increasing demand will have.

The main commercial argument against development of shale gas in China is the gas transport issue. The success of shale gas in North America was to a large degree based on the existence of an extensive gas pipelines network. There is nothing comparable to that in China, and despite the fact that the government is building pipelines at an unprecedented speed, it will take years if not decades, to achieve the same level of coverage as in North America.

On the other hand, the environmental issues in China do not have the same priority as in North America or Europe. Economic growth is still the paramount goal for the population at large and for political decision-makers. Therefore, the possible negative impact of shale gas development on the environment is not a front line issue.

It appears that there is a consensus in the global gas industry that makes China an attractive market for foreign companies. The global oil majors such as Shell, Chevron and ConocoPhillips are already involved in shale gas activities in China. They are now followed by a myriad of smaller players looking for quick profits, including a number of Chinese companies with no experience in gas or energy business.

It is however clear already today that further development of shale gas in China will have a significant impact on the entire world, both in terms of gas prices and environmental implications.

2. Coalbed methane

Coalbed methane (also known as colliery gas or coal seam gas) is present in some coal seams. It can be found in absorbed form within the coal matrix or unabsorbed in gaseous pockets. The gas generally lacks hydrogen sulphide but has a potentially higher level of carbon dioxide than natural gas. This resource is usually found at depths of 300-2000 metres below ground.

Coalbed methane production is associated with normal coal extraction and to date has only been commercialised where customers for gas are within the locality of the coal mining operation. The extraction of this unconventional gas resource involves horizontal drilling and fracturing techniques related to those used in oil shale extraction. It has been a growing source for gas production in certain regions, notably North America and Oceania. The recent rise in importance of shale gas may have an impact on coalbed methane's role as an unconventional source for natural gas in the future.

3. Tight gas

Tight gas refers to natural gas deposits which are particularly difficult to access from a geological viewpoint. Contained in rocks with very low permeability in deep formation, typically deeper than 4500m, extraction of this gas would require a combination of extraction processes such as the hydraulic fracturing and horizontal drilling. Some countries, such as the United States of America do not make a clear distinction in reported reserves between natural gas and tight gas. Known reserves are found in countries with well-established gas industries, where significant detailed surveying has been conducted; including but not limited to the USA, UK, Russia and Canada.

4. Methane hydrates

Crystalline deposits of methane, the principal component of natural gas, are found in extensive seams under deep water in various parts of the world. A recent academic assessment of gas hydrates calculates the amount of gas hydrates in resource-grade deposits to be at least one third more than 2010 estimates of global natural gas reserves.2

A number of countries have clearly demonstrated their interest in this potential form of energy, including Canada, China, Japan, Norway and the United States. In March 2013 the Japanese JOGMEC Corporation was the first company to extract gas from offshore methane hydrates, with the aim of commercial production starting by early 2019.

2 Boswell, R. and Collett, T.S., 2011. Current perspectives on gas hydrate resources. Energy and Environmental Science, 4, 1206-1215

4

Uranium and Nuclear

Contents

Strategic insight

This Commentary is based on the findings of the WEC report Global Nuclear Energy: One Year Post Fukushima published in 2012 and on the information and data provided by the International Atomic Energy Agency and WEC Member Committees.

1. Uranium

Uranium is a naturally-occurring element in the Earth. Traces of uranium can be found practically everywhere, although mining takes place in locations where uranium is naturally concentrated. To produce nuclear fuel from the uranium ore, uranium has to be enriched and formed into pellets which are loaded into the reactor fuel rods. Uranium is mined in 20 countries, although about half of world production comes from just ten mines in six countries: Australia, Canada, Kazakhstan, Namibia, Niger and Russia. In the conventional mining, the ore goes through a mill where it is crushed and then ground in water to produce a slurry of fine ore particles suspended in the water. The slurry is leached with sulphuric acid to dissolve the uranium oxides, leaving the remaining rock and other minerals undissolved.

Today, nearly half the world's mines use in situ leaching (ISL), where groundwater injected with oxygen is circulated through the uranium ore, extracting the uranium. The solution containing dissolved uranium is then pumped to the surface. This mining method does not cause any major ground disturbance. Both mining methods produce a liquid with dissolved uranium. The liquid is filtered and the uranium is separated by ion exchange, filtered and dried to produce a uranium oxide concentrate (U3O8), which is then sealed in drums. This concentrate has a bright yellow colour and is called 'yellowcake'. The U3O8 is only mildly radioactive. The radiation level one metre from a drum of freshly-processed U3O8 is about half that experienced from cosmic rays on a commercial jet flight.

The uranium market has been in decline over the past decade. Total annual mine production has fallen below the fresh fuel requirements of all operating reactors in the world. This is a consequence of the on-going disarmament and an emerging "secondary" market for reactor fuel from warheads and other military and commercial sources. The "secondary" market drastically reduced demand for fresh uranium and this reduction in demand was amplified by the new suppliers from Russia, Kazakhstan and Uzbekistan. At its lowest, the total global production of uranium fell down to about 60% of the annual reactor fuelling requirements.

The recent assessments of global uranium resources show that total identified resources have grown by 12.5% since 2008. However, the costs of uranium production have also increased. As of 1 January 2011 the total identified resources of uranium are considered sufficient for over 100 years of supply based on current requirements.

Global uranium production increased by over 25% between 2008 and 2010, mainly because of increased production by Kazakhstan, the world's leading producer. The uranium resource and production capacity have grown over the past few years reflecting a 22% increase in uranium exploration and mine development activities between 2008 and 2010, which in 2010 surpassed US$2 billion.

Along with the production, uranium enrichment capacity markets are changing. China, for example which is already using Russian centrifuges, has reached 1.3 million SWUs and has recently agreed with Russia to add further 0.5 million SWUs. Limited enrichment facilities for domestic needs exist in Argentina, Brazil, India and Pakistan. Ukraine joined Armenia, Kazakhstan and the Russian Federation as members of the International Uranium Enrichment Centre (IUEC).

The IUEC was established in 2007 in Angarsk, Russian Federation, following calls by the IAEA's Director General and the Russian President to work towards multinational control of enrichment and create a network of international centres, under IAEA control for nuclear fuel cycle services, including enrichment.

Total global fuel fabrication capacity is currently about 13 000 tU/yr (enriched uranium) for light water reactor (LWR) fuel and about 4 000 tU/yr (natural uranium) for PHWR fuel. Total demand is about 10 400 tU/yr. Some expansion of current facilities is under way in China, Republic of Korea and the USA. The current fabrication capacity for MOX fuel is around 250 tonnes of heavy metal (tHM), mainly located in France, India and the UK, with some smaller facilities in Japan and the Russian Federation. Additional MOX fuel fabrication capacity is under construction in the USA to use surplus weapon-grade plutonium. Genkai-3 in Japan started operating with MOX fuel in November 2009, making it the first Japanese reactor to use MOX fuel. Worldwide, 31 thermal reactors currently use MOX fuel.

The total amount of spent fuel that has been discharged globally is approximately 320 000 tHM. Of this amount, about 95 000 tHM has already been reprocessed, and about 310 000 tHM is stored in spent fuel storage pools at reactors or in away-from-reactor (AFR) storage facilities. AFR storage facilities are being regularly expanded, both by adding modules to existing dry storage facilities and by building new ones. Six countries operate reprocessing facilities and recycle parts of the plutonium in the form of MOX for reuse in nuclear power plants. Some countries build up plutonium stockpiles for fuelling future fast-breeder programmes. Total global reprocessing capacity is about 5 000 tHM/yr.

The Swedish Nuclear Fuel and Waste Management Company (SKB) selected Östhammar as the site for a final spent-fuel geological repository in June 2009, following a nearly 20-year process that narrowed the list of voluntary applicant sites to two in 2002. Subsequent site investigations concluded that the bedrock in Östhammar was more stable with less water than that in Oskarshamn, the other potential site.

Site investigations for repositories at Olkiluoto in Finland and in the Bure region in France continued on schedule with operation targeted for 2020 and 2025 respectively.

In the USA, the Government decided to terminate its development of a permanent repository for high-level waste at Yucca Mountain, while continuing the licensing process. It plans to establish a commission to evaluate alternatives.

Market trends

Demand for uranium is expected to continue to rise for the foreseeable future. Although the Fukushima Daiichi accident has affected nuclear power projects and policies in some countries, nuclear power remains a significant part of the global energy mix accounting for more than 13% of global electricity production. While some countries have plans for development of nuclear power, with the strongest expansion expected in China, India, the Republic of Korea and the Russian Federation, the overall global trend is still unclear. The long lead times (typically ten years or more in most producing countries) necessary to develop uranium production facilities require timely decisions.

Technical and economic considerations

There also are alternative technologies with far smaller fuel requirements. Fast reactors for example operating in a closed fuel cycle could provide energy for thousands of years. They represent a versatile and flexible technology which can create or “breed” more fuel than it is spending by converting nuclear “waste” into “fissile” material. “Fissile” material is nuclear fuel, usually uranium or plutonium that can sustain a fission chain. The heat generated by that fission chain reaction contained within a nuclear reactor produces steam to drive turbines and produce electricity.

“Waste” to Energy

The technology relies upon a “closed fuel cycle”, which means that spent fuel is reprocessed after its initial use in a reactor. Instead of sending the spent fuel into storage and eventually long-term disposal, the materials are reused, in particular the “fertile” material. The “fertile” material is not fissionable, but it can be converted into fissionable material by exposure to radiation in a reactor. Once converted into fissile material, it will be consumed in the chain reaction. This conversion from “fertile” to “fissionable” material significantly improves nuclear fuel efficiency and economics. Fast reactors can thus be used to breed more fissile material than they consume or to burn nuclear waste or for a combination of these two operations offering significant benefits in making nuclear energy production more sustainable, both in technical and economic terms.

Fast breeder technology was developed in the 1960s with demonstration and prototype reactors in a number of countries, including China, France, Germany, India, Japan, the Russian Federation, the United Kingdom and the United States. There are 12 experimental fast reactors and six commercial size prototypes with output of 250-1200 MW that have been constructed or are in operation.

The Russian Federation currently operates the most powerful commercial fast reactor, the BN-600 in Beloyarsk, and building the BN-800. The recently released Federal Target Programme *New Generation Nuclear Power Technologies for 2010-2015 With Outlook to 2020*, outlines Russia’s plans to develop several fast reactor technologies and corresponding fuel cycles.

A number of other initiatives, including the Generation IV International Forum and the IAEA’s International Project on Innovative Nuclear Reactors and Fuel Cycles (INPRO), include research on fast reactor technology. Experts expect that the first Generation IV fast reactor demonstration plants and prototypes will be in operation by 2030 to 2040.

On 3 December 2010, the IAEA Board of Governors authorised the IAEA Director General to establish a reserve of low enriched uranium (LEU), or an “IAEA LEU Bank” owned and managed by the IAEA. The bank will help secure supplies of LEU for power generation in case of supply disruptions which cannot be addressed by the commercial market, State-to-State arrangements or by other means. This initiative does not in any way influence individual countries’ rights to establish or expand their own nuclear fuel production.

Donors have pledged about 125 million US dollars and 25 million Euros to cover the initial operational expenses and the purchase of LEU for the IAEA LEU bank. The operating costs of the bank will have no financial implications for the IAEA regular budget. These financial resources will be sufficient to meet the fuel fabrication needs for two to three reloads of fuel for a 1,000 MW(e) light water reactor. The LEU will be made available to an eligible IAEA Member State at the market price and the proceeds will then be used to replenish the stock in the IAEA LEU bank. As a mechanism of last resort, LEU can only be supplied to a Member State upon an advance payment and meeting a set of criteria.

Donors' contributions:

	Pledged	Paid
Kuwait	US$10m	In full
Norway	US$5m	In full
United Arab Emirates	US$10m	0
United States	US$49.540m	In full
European Union	€25m	€20m
Nuclear Threat Initiative	US$50m	In full

2. Nuclear

The first nuclear reactor was in the world was commissioned in the Former Soviet Union Obninsk Nuclear Power Plant in 1954. Since then, the nuclear industry has developed over three distinct periods:

1. The first "fast growth" period between 1954 and 1974 witnessed an average growth rate of about seven reactors per year until 1965, increasing to about 37 reactors per year in 1970 and more following the first oil shock of 1973-1974.

2. The second period from the late 1970s to the mid-2000 was a period of extremely low development, averaging additions of 2-3 new reactors per year only. High capital costs of nuclear and low oil and gas prices were the main factors resulting in the slowdown. The situation was aggrevated further by the two major nuclear accidents: the Three Mile Island (USA, 1979) and the Chernobyl (Ukraine, 1986).

3. The third period from the mid-2000s until the beginning of 2011 once again witnessed an accelerating growth called the "nuclear renaissance". In terms of geographical distribution, the growth was no longer in the OECD countries but mainly in the quickly developing Asian economies (mainly China). That growth was also justified by nuclear's relative cost-effectiveness compared to fossil fuels. In addition, environment, political decisions and weak public opposition in the main countries of growth were the main contributing factors.

Despite the identified negative developments throughout these three periods, the total nuclear production has been growing and reached the annual production of about 2,600TWh by the mid-2000s. The nuclear share of total global electricity production reached 17% by the late 1980s, but since then has been falling and dropped to 13.5% in 2010.

There are a number of reasons for these conflicting trends. They include financial and economic developments, rapidly increasing energy demand due to population growth and social and economic development, and concerns about energy security and the environment, just to name a few.

The economic crisis of the late 2000s was a main contributing factor for delays or cancellations of nuclear projects in some regions of the world. The Swedish utility Vattenfall announced in June 2009 that it was putting decisions on nuclear new build on hold for 12–18 months, citing the economic recession and market situation. Financing uncertainty was cited in connection with the withdrawal of the utilities GDF SUEZ and RWE from the Belene project in Bulgaria. The Russian Federation announced that for the next few years, because of the financial crisis and lower projected electricity use, it would slow planned expansion from two reactors per year to one. Ontario, Canada, suspended a programme to build two replacement reactors at Darlington, partly because of uncertainty about the future of Atomic Energy of Canada Limited (AECL). The Canadian Government had reported that it planned to seek buyers for AECL to reduce budget deficits. In the USA, Exelon deferred major pre-construction work on a proposed new nuclear power plant in Texas, citing uncertainties in the domestic economy. Of 17 combined licence applications before the U.S. Nuclear Regulatory Commission (NRC), four were put on hold in 2009 at the request of the applicants. In South Africa, Eskom extended the schedule for its planned next reactor by two years to 2018.

In contrast, China saw nine construction starts in 2009 after six in 2008. It appears that as utilities elsewhere dragged their feet in following through with nuclear plant and equipment orders, China seized the opportunity, moving ahead in the queue and negotiating attractive terms. As the year 2009 drew to a close, the United Arab Emirates announced the signing of a contract to purchase four 1 400 MW_e reactors from a South Korean consortium led by the Korea Electric Power Corporation. About a dozen countries currently without nuclear power are continuing preparations to start their first nuclear power plants by the early 2020s, while an even larger number are familiarising themselves with the prerequisite nuclear infrastructure requirements.

Globally, the nuclear industry is in decline: The 427 reactors operating today are 17 reactors less than at the peak in 2002. Annual nuclear electricity generation reached a maximum of 2,660TWh in 2006, but dropped to 2,346 TWh in 2012 (down by 7% compared to 2011 and down by 12% compared to 2006). About three-quarters of this decline can be attributed to the events in Japan, but 16 other countries, including the top five nuclear generators, decreased their nuclear generation capacities, too.

Another factor impacting the global share of nuclear is the temporary unavailability of several reactors at nuclear power plants in Japan, which were shut down in July 2007 after a major earthquake. After in-depth safety inspections and seismic upgrades, two of the seven units were restarted and connected to the grid in 2009.

The “big five” nuclear generating countries:

- United States
- France
- Russia
- South Korea
- Germany

account for 67% of the total nuclear generated electricity in the world. The countries with a steady increase in nuclear generation are China, Czech Republic and Russia.

Market trends

In Europe, nuclear power phase-out policies have been scaled down in several countries. Sweden for example will now allow its existing reactors to operate to the end of their economic lifetimes and to be replaced by new reactors once they are retired. Italy ended its ban on nuclear power and might now allow new construction. Belgium decided to postpone the first phase of its planned phase-out by ten years. Closure of its reactors had been scheduled to take place between 2015 and 2025.

Fourteen countries are currently building nuclear power plants, one more than a year ago as the United Arab Emirates (UAE) started construction at Barrakah. The UAE is the first new country in 27 years to have started building a commercial nuclear power plant.

As of July 2013, 66 reactors are under construction (7 more than in July 2012) with a total capacity of 63 GW. The average construction time as of the end of 2012, was 8 years. However, nine reactors have been listed as “under construction” for more than 20 years and four additional reactors have been listed for 10 years or more. Forty-five projects do not have an official planned start-up date on the International Atomic Energy Agency’s (IAEA) database. At least 23 projects have encountered construction delays, and for the remaining 43 reactor units, either construction began within the past five years or they have not yet reached projected start-up dates, making it difficult or impossible to assess whether they are on schedule or not.

Two-thirds (44) of the units under construction are located in three countries: China, India and Russia. The average construction time of the 34 units that started up in the world between 2003 and July 2013 was 9.4 years.

Only three reactors started up in 2012, while six were shut down and in 2013 up to July, only one started up, while four shutdown decisions were taken in the first half of 2013, all of them in the US. Three of those four units faced costly repairs, while one at Kewaunee, Wisconsin was running well and had received a license renewal just two years ago to operate up to a total of 60 years. However, in the meantime, it became uneconomic to run.

Technical and economic considerations

Construction costs are a key factor for the final electricity generating costs and many current nuclear projects are significantly over budget. Cost estimates have increased in the past decade from US$1,000 to US$7,000 per kW installed.

The stock market value of the world’s largest nuclear operator, French state utility EDF, went down by 85 percent over the past five years, while the share price of the world’s largest nuclear builder, French state company AREVA, dropped by up to 88 percent.

Generally, existing operating nuclear power plants continue to be highly competitive and profitable. The low share of fuel cost in total generating costs makes them the lowest-cost base load electricity supply option in many markets. Uranium costs account for only about 5% of total generating costs and thus protect plant operators against resource price volatility.

Using a levelised cost of electricity (LCOE) calculation formula, new nuclear build is generally competitive with other generating options. The ‘front-loaded’ cost structure of nuclear plants (i.e. the fact that they are relatively expensive to build but inexpensive to operate) has always been an investment risk factor and a financial challenge, especially in competitive electricity markets.

Apart from the market related factors, there are other factors that have an impact on the development of nuclear power. On the production side, there are only a few manufacturers in the world that are capable of producing heavy forging equipment such as reactor pressure vessels or steam generators.

Another factor is carbon pricing which can improve the economics of nuclear power relative to fossil-fuelled generation.

Market trends and outlook

Each year the IAEA updates its low and high projections for global growth in nuclear power. In the updated low projection, global nuclear power capacity reaches 511 GW_e in 2030, compared to a capacity of 370 GW_e at the end of 2009. In the updated high projection it reaches 807 GW_e. The upward shift in the projections is greatest for the Far East, a region that includes China, Japan and the Republic of Korea. Modest downward shifts in the projections were made for North America and for Southeast Asia and the Pacific.

Although today the key drivers and market players defining the future of nuclear power are different from those 20-30 years ago, the emerging non-OECD economies (mainly China and India) are expected to dominate future prospects. Given that they need to use all options to meet their rapidly growing electricity demand and secure certain economic growth levels at high rates, it will constitute a major and potentially costly challenge to rule out the option of using larger shares of nuclear power.

Furthermore, these challenges will be amplified by the increasing energy price from other sources, political stability in certain energy producing markets, in addition to carbon emission and climate change concerns. The developing nations (China, Russia and India) seem to have kept most of their planned projects alive.

Despite the relatively high costs, recent accidents and growing public opposition in some regions, nuclear power is back on the agenda of many countries, primarily for following three reasons: it has predictable long-term generation costs, as it is not exposed to the volatile fossil fuels markets, and it can enhance energy security and bring along climate-change mitigation benefits. Nuclear's economic competitiveness depends on local conditions including available alternatives, market structures and government policy.

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Reserves and production

Table 1

Nuclear Energy: capacity, generation and operating experience at 1 July 2013

Source: Power Reactor Information System, International Atomic Energy Agency

	Reactors in operation		Reactors under construction		Net capacity	Nuclear share of electricity generation in 2011	Total operating experience to end-2011	
	Units	Capacity	Units	Capacity				
	number	MWe	number	MWe	TWh	%	years	months
Argentina	2	935	1	692	6	5	62	7
Armenia	1	375			3	45	35	8
Belgium	7	5 926			45	52	233	7
Brazil	2	2 007	1	1 405	16	3	37	3
Bulgaria	2	2 000			15	32	147	3
Canada	17	12 009			90	15	582	2
China	18	13 816	28	19 920	70	2	99	3
Czech Republic	6	3 970			27	33	110	10
Finland	4	2 736	1	16 00	22	26	123	4
France	59	63 130	1	1 600	368	77%	1 700	2
Germany	9	12 068			102	18	751	5
Hungary	4	1 889			16	46	98	2
India	18	4 388	7	4 800	19	2	318	4
Iran (Islamic Rep.)	1	915	1	915	1	1	0	3
Japan	54	48 960	3	4 141	163	19	1 439	5
Korea (Republic)	23	20 718	3	3 600	99	30	339	8
Lithuania						76	43	6
Mexico	2	1 365			10	4	35	11
Netherlands	1	482			4	4	65	-
Pakistan	2	425	1	300	5	3	47	10
Romania	2	1 300			12	20	15	11
Russian Federation	33	23 643	9	6 500	153	18	994	4
Slovakia	4	1 816	2	810	15	54	132	7
Slovenia	1	688			6	39	28	3
South Africa	2	1 860			2	5	50	3
Spain	7	7 112			58	21	269	6
Sweden	10	9 395			61	40	372	6
Switzerland	5	3 263			26	40	173	10

Taiwan, China	6	4 949	2	2 600	40	21	170	1
Ukraine	15	13 107	2	1 900	78	49	368	6
United Kingdom	16	9 243			56	18	1 457	8
USA	104	98 903	3	1 165	799	19	3 499	9
Total World	**437**	**364 078**	**65**	**51 948**	**2 386**	**-**	**5 695**	**6**

Notes:

The capacity and output of the Krsko nuclear power plant, shown against Slovenia in the table, is shared 50/50 between Slovenia and Croatia

Total world operating experience includes reactor years for Italy and Kazakhstan which no longer operate nuclear power plants

Table 2

Nuclear fuel cycle capability

Source: NEA, 2008

	Conversion	Enrichment	Fuel fabrication	Reprocessing
Argentina	X		X	
Belgium			X	
Brazil	X		X	
Canada	X		X	
China	X	X	X	X
France	X	X	X	X
Germany		X	X	
India	X		X	X
Japan		X	X	X
Kazakhstan			X	
Korea (Republic)			X	
Netherlands		X		
Pakistan	X	X	X	
Romania			X	
Russian Federation	X	X	X	X
Spain			X	
Sweden			X	
United Kingdom	X	X	X	X
United States of America	X	X	X	

Country notes

The Country Notes on Nuclear have been compiled largely on the basis of material published in:

- *WNN Weekly,* World Nuclear Association, London;
- *WNN Weekly Digest*, World Nuclear Association, London;
- Press reports and industry web sites.

Information provided by WEC Member Committees has been incorporated when available.

Argentina

No. of reactors in operation Capacity MWe	2 935
No. of reactors under construction Capacity MWe	1 692
Net generation in 2011, TWh	5 892
Nuclear share of electricity generation	5%

Argentina has two nuclear reactors Atucha-I (335 MWe PHWR) and Embalse (600 MW_e PHWR) generating nearly one-tenth of the country's electricity demand. The third reactor is expected to be commissioned in 2013.

The fourth NPP, consisting of two units each of 750 MWe, is planned to be connected to the network in 2016/2017. The Member Committee foresees that by the end of 2020 four reactors will be in operation in Argentina, with an aggregate capacity of 3 232 MWe.

Armenia

No. of reactors in operation Capacity MWe	1 375
No. of reactors under construction Capacity MWe	0
Net generation in 2011, TWh	2 550
Nuclear share of electricity generation	**27%**

Armenia has relied heavily on nuclear power since 1976 when the first of the two original WWER units was commissioned. The nuclear power plant is located close to the capital Yerevan (64 km), and one of the two reactors was shut down in 1989 following an earthquake the previous year. The second 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. This unit supplies about a third of the total electricity produced in the country (2.4 billion kWh). Armenia has faced international pressure, especially from its neighbour Turkey, to shut down Medzamor-2 on the grounds of safety, and the government has approved a joint venture to build another plant by 2020.

Australia

No. of reactors in operation Capacity MWe	0
No. of reactors under construction Capacity MWe	0
Net generation in 2011, TWh	0
Nuclear share of electricity generation	**0%**

Australia has significant uranium resources and an adequate infrastructure to support any future nuclear power development. As well as the Australian Nuclear Science & Technology Organisation (ANSTO), which owns and runs the modern 20 MWt Opal research reactor, there is a world-ranking safeguards set-up - the Australian Safeguards & Non-proliferation Office (ASNO), the Australian Radiation Protection and Nuclear Safety Agency (ARPANSA) and a well-developed uranium mining industry. However, in contrast to most G20 countries, the only driver for nuclear power in Australia is reduction of CO_2 emissions, or costs arising from that. Apart from this, economic factors and energy security considerations do not make it necessary.

In December 2006 the report of the Prime Minister's expert taskforce considering nuclear power was released. It said nuclear power would be 20-50% more expensive than coal-fired power and (with renewables) it would only be competitive if "low to moderate" costs are imposed on carbon emissions (A$ 15-40 - US$ 12-30 - per tonne CO2). "Nuclear power is the least-cost low-emission technology that can provide base-load power" and has low life cycle impacts environmentally.

Bangladesh

No. of reactors in operation Capacity MWe	0
No. of reactors under construction Capacity MWe	0
Net generation in 2011, TWh	0
Nuclear share of electricity generation	**0%**

Bangladesh plans to have two 1000 MWe Russian nuclear power reactors in operation from 2020. This is to meet rapidly-increasing demand and reduce dependence on natural gas. Today, about 88% of electricity comes from natural gas, electricity demand is rising rapidly, with peak demand of 7.5 GWe.

Belarus

No. of reactors in operation Capacity MWe	0
No. of reactors under construction Capacity MWe	0
Net generation in 2011, TWh	0
Nuclear share of electricity generation	**0%**

Belarus plans to have its first nuclear power plant built with Russian finance to come into operation in 2018. Atomstroyexport has been contracted to build the 2400 MWe plant. Under its 2011-2020 energy strategy, Belarus is seeking to reduce its reliance on Russia as a major energy supplier. The plan calls for a 1000 MWe coal-fired plant and a 2400 MWe nuclear power plant as well as four hydropower stations with total capacity of 120 MW, and wind projects totaling 300 MW. Government plans to reform the electricity sector by creating a wholesale market in three stages have stalled, and electricity remains heavily subsidised for households.

The country imports 90% of its gas from Russia (estimate of 22.5 billion m^3 in 2012) - much of it for electricity, and overall aims for 25-30% energy independence, compared with half that now. The proposed 2400 MWe nuclear plant is expected to reduce gas imports by 5 billion m^3 per year, now costing over US$ 800 million, while the nuclear fuel and waste management would be a quarter of this. In November 2011 it was agreed that Russia's Gazprom would pay US$2.5 billion for the 50% of Belarus' gas transmission network, Beltransgaz, that it did not already own. This was linked both to lower gas prices and to Russian finance for the nuclear plant. Earlier, there had been studies on both a domestic nuclear power plant using Russian technology, and Belarus participation in a new nuclear unit at Smolensk or Kursk in Russia.

Belgium

No. of reactors in operation Capacity MWe	7 5 926
No. of reactors under construction Capacity MWe	0
Net generation in 2011, TWh	45
Nuclear share of electricity generation	**51%**

Belgium has seven nuclear reactors generating about half of its electricity. Belgium's first commercial nuclear power reactor began operation in 1974: four units at Doel and three at Tihange. they are all of the same PWR type, with a current aggregate net generating capacity of 5 863 MW_e. There has been little government support for nuclear energy, and nuclear power generation incurs a EUR 0.5 cent/kWh tax.

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'. In October 2009 the Belgian Government announced that its plans for phasing out nuclear power would be put back for ten years.

Most of electricity in Belgium is produced by Electrabel, a subsidiary of GDF Suez, which also operates all the nuclear plants.

Brazil

No. of reactors in operation Capacity MWe	2 2 007
No. of reactors under construction Capacity MWe	1 1 405
Net generation in 2011, TWh	16
Nuclear share of electricity generation	**3%**

Brazil has two nuclear reactors: Angra-1 (491 MW_e net PWR) and Angra-2 (1 275 MW_e net). generating 3% of Brazil's electricity. Its first commercial nuclear power reactor began operating in 1982. Work on the construction of a third unit at Angra, of similar size to Angra-2, was started in 1983, but suspended after a few years.

Bulgaria

No. of reactors in operation Capacity MWe	2 2 000
No. of reactors under construction Capacity MWe	0
Net generation in 2011, TWh	15
Nuclear share of electricity generation	**32%**

Bulgaria has two nuclear reactors generating over 32% of its electricity. Originally, 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 other (each of 953 MW_e capacity) were commissioned in 1987 and 1989, respectively.

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.

Government's commitment to the future of nuclear energy is strong, although financing construction of new units will not be easy. Construction of a new nuclear plant was planned, but instead it was decided to add a third 1000 MWe unit to the existing plant. The country has been a significant exporter of power. However, with the closure of two older nuclear units at the end of 2006, electricity exports have dropped somewhat. Three large lignite plants supply about half the country's electricity.

Canada

No. of reactors in operation Capacity MWe	17 12 009
No. of reactors under construction Capacity MWe	0
Net generation in 2011, TWh	90
Nuclear share of electricity generation	**15%**

About 15% of Canada's electricity comes from nuclear power, with 17 reactors mostly in Ontario province providing 12 GWe of power capacity. Canada plans to expand its nuclear capacity over the next decade by building two more new reactors. For many years Canada has been a leader in nuclear research and technology exporting reactor systems as well as a high proportion of the world supply of radioisotopes used in medical diagnosis and cancer therapy.

Canada generated 636 billion kWh in 2011, of which about 15% was from nuclear generation, compared with 59% from hydro, 13% from coal and 8.4% from gas. According to a study by the Canadian Energy Research Institute,[1] in 2005 Canada's 18 nuclear reactors sold energy worth almost C$5billion, contributed C$6.3 billion to GDP, and created C$1.4 billion in government revenue. The nuclear power industry employed, directly and indirectly, over 66,000 people. About C$13.26 billion (in 2005 dollars) was invested by the government in Canada's nuclear program over 1952-2006 through AECL. This investment has generated more than C$160 billion in GDP benefits to Canada from power production, research and development, Candu exports, uranium, medical radioisotopes and professional services, according to AECL.

All Canadian nuclear plants are Pressurized Heavy Water Reactors (PHWR) type, using the CANDU design. The total installed nuclear capacity in Canada is approximately 14,000 MW in Ontario and New Brunswick.

China

No. of reactors in operation	18
Capacity MWe	13 816
No. of reactors under construction	28
Capacity MWe	19 920
Net generation in 2011, TWh	70
Nuclear share of electricity generation	**2%**

Nuclear power plays an important role in China, especially in the coastal areas located far from the coal mines and where the economy is developing rapidly. Development of nuclear power in China commenced in 1970 and about 2005 the industry moved into a rapid development phase. Technology has been drawn from France, Canada and Russia, with local development based largely on the French element. The latest technology acquisition has been from the USA (via Westinghouse, owned by Japan's Toshiba) and France. The Westinghouse AP1000 reactor is the main basis of technology development in the immediate future.

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. Ten more NPPs (eight PWRs and two PHWRs) have subsequently been installed. Tianwan 2, a Russian-built 1 000 MW_e (gross) WWER, began commercial operation on 16 August 2007. Excavation of the site for the Sanmen NPP in Zhejiang province got under way in February 2008, with construction commencing officially in April 2009. Shortly afterwards it was reported that an agreement had been signed for the construction of China's first inland NPP at Xianning City, Hubei. In October 2009 it was reported that a high-level agreement had been signed with Russia for design work on two 800 MW_e fast neutron reactors for construction in China.

April 2010 witnessed a number of progress reports on China's nuclear building programme. First concrete was poured at the sites of the Taishan (Guangdong) and Changjiang (Hainan) NPPs, while fuel loading began at Unit 1 of the second phase of the Ling Ao NPP, also in Guangdong.

Czech Republic

No. of reactors in operation Capacity MWe	6 3 970
No. of reactors under construction Capacity MWe	0
Net generation in 2011, TWh	27
Nuclear share of electricity generation	**33%**

The Czech Republic has six nuclear reactors generating about one-third of its electricity. The first commercial nuclear power reactor began operating in 1985. Government commitment to the future of nuclear energy is strong. Electricity generation in the Czech Republic has been growing since 1994 and in 2011, 87.6 billion kWh was generated from 20 GWe of plant, of which 57% (49.7 billion kWh) was from coal, 33% (27 billion kWh) from nuclear, with net exports of 17 billion kWh[a]. More than 80% of the country's gas comes from Russia.

A draft national energy policy to 2060 issued in 2011 indicated a major increase in nuclear power, to reach 13.9 GWe or up to 18.9 GWe in the case of major adoption of electric vehicles. It would then provide some 60% of the country's power. The version adopted in November 2012 assumed at least 50% of future generation coming from nuclear, with two new reactors being built at Temelin and one at Dukovany to take production to 46.5 TWh by 2025, and 55.2 TWh/yr later, hence further nuclear sites should be identified. The current four units at Dukovany would get 20-year life extensions, to 2045-47. Nuclear plants should supply district heating to Brno and other cities by 2030.

Finland

No. of reactors in operation Capacity MWe	4 2 736
No. of reactors under construction Capacity MWe	1 1 600
Net generation in 2011, TWh	22
Nuclear share of electricity generation	**26%**

Finland has four nuclear reactors providing over 30% of its electricity. Four nuclear reactors were brought into operation between 1977 and 1980: two 488 MW_e WWERs at Loviisa, east of Helsinki, and two 840 (now 860) MW_e BWRs at Olkiluoto. The construction licence for building Finland's fifth reactor, Olkiluoto 3, was granted by the Government in early 2005, subsequent to a Decision-in-Principle ratified by Parliament in 2002. The new nuclear power unit of 1 600 MW_e (net) has for a number of reasons experienced considerable delays in construction and is not expected to begin commercial operation any time soon.

In 2011 electricity production in the country was 73.5 TWh, with nuclear providing 23 TWh. Provisions for radioactive waste disposal are well advanced in Finland.

Since the 1930s energy-intensive industry has invested in large-scale energy production in Finland, rather than leaving it entirely to specialized utilities. More recently energy-intensive companies have seen joint ownership of electricity production with power sold at cost price to shareholders as an important means of protection against the increasing prices and volatility of liberalised electricity markets. This so-called Mankala model is also effective in risk-sharing. It is a distinctive of Finland in relation to capital-intensive nuclear capacity.

France

No. of reactors in operation	59
Capacity MWe	63 130
No. of reactors under construction	
Capacity MWe	
Net generation in 2011, TWh	368
Nuclear Share of electricity generation	**77%**

France has 59 nuclear reactors operated by Electricite de France (EdF), with the total capacity of over 63 GWe supplying 368 billion kWh per year, i.e. 77% of the total generated electricity that year. About 17% of France's electricity is from recycled nuclear fuel. 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. Apart from a single fast reactor (Phenix), PWRs account for the whole of current nuclear capacity. The present setup of the electricity industry in France is a result of the government decision in 1974, just after the first oil shock, to expand rapidly the country's nuclear power capacity using Westinghouse technology. This decision was taken in the context of France having substantial heavy engineering expertise but few indigenous energy resources. Nuclear energy, with the fuel cost being a relatively small part of the overall cost, made good sense in minimising energy imports and achieving greater energy security.

Referring to the 1974 decision and the following actions, France now claims a substantial level of energy independence and almost the lowest cost of electricity in Europe. It also has an extremely low level of CO_2 emissions per capita from electricity generation, since over 90% of its electricity is nuclear or hydro. In mid 2010 a regular energy review of France by the International Energy Agency urged the country increasingly to take a strategic role as provider of low-cost, low-carbon base-load power for the whole of Europe rather than to concentrate on the energy independence which had driven policy since 1973.

Construction of EDF's first European Pressurised Water Reactor (EPR), net capacity 1 600 MW_e) began at Flamanville (Normandie) towards the end of 2007, with completion scheduled for 2012. Work on a second EPR is planned to start at Penly in 2012.

France is the world's largest net exporter of electricity due to the very low cost of generation and it earns over 3 billion Euros per year from electricity sales abroad. France has been very active in developing nuclear technology. Reactors and fuel products and services are a major export. Currently, it is building its first Generation III reactor and planning a second.

Germany

No. of reactors in operation	9
Capacity MWe	12 068
No. of reactors under construction	0
Capacity MWe	
Net generation in 2011, TWh	102
Nuclear share of electricity generation	**18%**

Germany has 9 nuclear reactors which supply almost one fifth of its electricity demand. A coalition government formed after the 1998 federal elections had the phasing out of nuclear energy as a feature of its policy. With a new government in 2009, the phase-out was cancelled, but then reintroduced in 2011, with eight reactors to shut down immediately. The cost of replacing nuclear power with renewables is estimated by the government to amount to some EUR 1000 billion. Public opinion in Germany remains negative to nuclear power and at present does not support building new nuclear plants. Germany's electricity production in 2011 was 629 billion kWh (TWh) gross with coal providing 278 TWh (45%, more than half being lignite), nuclear 108 TWh (17.5%), gas 84 TWh (13.7%), biofuels & waste 43.6 TWh (7.1%), wind 46.5 TWh (7.6%), hydro 24.6 TWh (4%), solar 19 TWh (3%). Electricity exports exceeded imports by about 4 TWh, compared with 15 TWh in 2010, but Germany remains one of the biggest importers of gas, coal and oil in the world, and has few domestic resources apart from lignite and renewables.

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 reactors due for closure under the phase-out plan are three PWRs; Biblis A (net capacity 1 167 MW_e, which came into service in 1975), Biblis B (1 240 MW_e, 1977) and Neckarwestheim (785 MW_e, 1976). Many of the units are large (they total 20,339 MWe), and the last came into commercial operation in 1989. Six units are boiling water reactors (BWR), 11 are pressurised water reactors (PWR). All were built by Siemens-KWU. A further PWR had not operated since 1988 because of a licensing dispute. This picture changed in 2011, with the operating fleet being reduced to nine reactors with 12,003 MWe capacity.

Hungary

No. of reactors in operation Capacity MWe	4 1 889
No. of reactors under construction Capacity MWe	0
Net generation in 2011, TWh	16
Nuclear share of electricity generation	**46%**

Hungary has four nuclear reactors generating more than one-third of its electricity. Its first commercial nuclear power reactor began operating in 1982. In 2011, total electricity generation in Hungary by 9 GWe of installed capacity was 36.2 billion kWh (gross), of which nuclear's share was 15.7 billion kWh (43%). Four WWER reactors, with a current aggregate net capacity of 1 859 MW_e, came into commercial operation at Paks in central Hungary, between 1983 and 1987. The Hungarian Parliament has expressed overwhelming support for building two new power reactors.

India

No. of reactors in operation Capacity MWe	18 4 388
No. of reactors under construction Capacity MWe	7 4 800
Net generation in 2011, TWh	19
Nuclear share of electricity generation	**2%**

India has 18 reactor units in operation, with an aggregate net generating capacity of 4 388 MW_e. Sixteen are PHWRs, the other two of the BWR type: most were relatively small units, with individual capacities up to 202 MW_e; the exception is Tarapur-3 and -4, each with a net capacity of 490 MW_e. Output from India's nuclear plants accounts for about 2.2% of its net electricity generation. According to the IAEA, five reactor units were under construction at the beginning of 2010, with an aggregate net generating capacity of 2 708 MW_e. Two 202 MW_e PHWRs were under construction at end-2009: Kaiga-4 and Rajasthan-6, as well as two 917 MW_e WWERs (Kudankulam-1 and -2) and a 470 MW_e fast breeder reactor (PFBR). Rajasthan-6 was connected to the grid at the end of March 2010.

In September 2009 the Indian cabinet endorsed the reservation of two coastal sites (Mithi Virdi in Gujarat and Kovada in Andhra Pradesh) for nuclear power parks, each with up to eight reactors. Towards the end of 2009, an agreement was announced for further cooperation between Russia and India in respect of four reactors planned for Kudankulam and others at Haripur in West Bengal.

India has a flourishing and largely indigenous nuclear power programme and expects to have 14,600 MWe nuclear capacity on line by 2020. It aims to supply 25% of electricity from nuclear power by 2050. Since India is outside the Nuclear Non-Proliferation Treaty due to its weapons programme, it was for 34 years largely excluded from trade in nuclear plant or materials, which has hampered its development of civil nuclear energy until 2009. Due to these trade bans and lack of indigenous uranium, India has uniquely been developing a nuclear fuel cycle to exploit its reserves of thorium. Now, foreign technology and fuel are expected to boost India's nuclear power plans considerably. India has a vision of becoming a world leader in nuclear technology due to its expertise in fast reactors and thorium fuel cycle.

Iran (Islamic Republic)

No. of reactors in operation Capacity MWe	1 915
No. of reactors under construction Capacity MWe	1 915
Net generation in 2011, TWh	1
Nuclear share of electricity generation	**1%**

Construction of two 1 200 MW_e PWRs started at Bushehr in the mid-1970s 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 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. The final shipment of nuclear fuel for Bushehr-1 arrived from Russia in January 2008. During February 2009, a 'pre-commission' test was carried out using 'virtual' fuel. Pre-start testing was reported to be in progress in January 2010. Commissioning tests continued during March. On 21 August the process of loading nuclear fuel into the first unit at Bushehr began under the supervision of inspectors from the IAEA.

A large nuclear power plant Bishehr-1 has started up in Iran, after many years construction, and it has been grid-connected. The country also has a major program developing uranium enrichment which was concealed for many years. Iran has not suspended its enrichment-related activities, or its work on heavy water-related projects, as required by the UN Security Council.

Italy

No. of reactors in operation Capacity MWe	0
No. of reactors under construction Capacity MWe	0
Net generation in 2011, TWh	0
Nuclear share of electricity generation	**0%**

Italy has had four operating nuclear power reactors but shut the last two down following the Chernobyl accident. Some 10% of its electricity comes today from nuclear power – all imported, however. The government intended to have 25% of electricity supplied by nuclear power by 2030, but this prospect was rejected at a referendum in June 2011.

Italy is the only G8 country without its own nuclear power plants, having closed its last reactors in 1990. In 2008, government policy towards nuclear changed and a substantial new nuclear build programme was planned. However, in a June 2011 referendum the 2009 legislation setting up arrangements to generate 25% of the country's electricity from nuclear power by 2030 was rejected.

Japan

No. of reactors in operation Capacity MWe	54 48 960
No. of reactors under construction Capacity MWe	3 4 141
Net generation in 2011, TWh	163
Nuclear share of electricity generation	**19%**

Japan has to import about 81% of its energy requirement. Its first commercial nuclear power reactor began operating in 1966, and nuclear energy has been a national strategic priority since 1973. This is now under review following the 2011 Fukushima accident. The country's 50 main reactors have produced about 30% of electricity and this share was expected to increase to at least 40% by 2017. The current estimate is for about half of this. Japan has a full fuel cycle set-up, including enrichment and reprocessing of used fuel for recycling.

Despite being the only country to have suffered the devastating effects of nuclear weapons in wartime, with over 100,000 deaths, Japan embraced the peaceful use of nuclear technology to provide a substantial portion of its electricity. However, following the tsunami which killed 19,000 people and which triggered the Fukushima nuclear accident, public sentiment shifted markedly and there were public protests calling for nuclear power to be abandoned. The balance between this populist sentiment and the continuation of reliable and affordable electricity supplies is being worked out politically.

According to IAEA data, there were 55 operable nuclear reactors at the end of 2008, with an aggregate generating capacity of 49 315 MW_e gross, 47 278 MW_e net. Within this total there were 28 BWRs (24 764 MW_e gross, 23 908 MW_e net), 23 PWRs (19 366 MW_e gross, 18 420 MW_e net) and four ABWRs (5 185 MW_e gross, 4 950 MW_e net). Tomari-3, an 866 MW_e (net) PWR entered commercial service on 22 December 2009. At the beginning of 2010, total net nuclear generating capacity was 46 823 MW_e in 54 reactors, which provided about 29% of Japan's net generation of electricity during the year. One reactor, Shimane-3 (a 1 325 MW_e ABWR) was under construction.

Jordan

No. of reactors in operation Capacity MWe	0
No. of reactors under construction Capacity MWe	0
Net generation in 2011, TWh	0
Nuclear share of electricity generation	**0%**

Jordan imports over 95% of its energy needs, at a cost of about one fifth of its GDP. It generates 14.3 billion kWh, mostly from natural gas, and imports 0.4 billion kWh of electricity for its six million people. Jordan is looking for ways to reinforce its energy security and at the same time keep lower electricity prices. Jordan is expected to start building a 750-1200 MWe nuclear power unit in 2013 to be commissioned by 2020 and a second unit for operation by 2025.

Kazakhstan

No. of reactors in operation Capacity MWe	0
No. of reactors under construction Capacity MWe	0
Net generation in 2011, TWh	0
Nuclear share of electricity generation	**0%**

Kazakhstan has 15% of the world's uranium resources and has been an important source of uranium for more than fifty years. Over 2001-2011 production rose from 2,022 to 19,450 tonnes U per year, thus making Kazakhstan the world's leading uranium producer. Mine development has continued with a view to further increasing annual production by 2018. The current capacity is around 25,000 tU/yr, but in October 2011 Kazatoprom announced a cap on production at 20,000 tU/yr. Of its 17 mine projects, 5 are wholly owned by Kazatomprom and 12 are joint ventures with foreign equity holders. A single Russian nuclear power reactor operated from 1972 to 1999, generating electricity for desalination .Kazakhstan has a major plant making nuclear fuel pellets and aims eventually to sell value-added fuel rather than just uranium. It aims to supply 30% of the world fuel fabrication market by 2015.

The government is committed to increased uranium exports, and is considering future options for nuclear power. 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.

A government plan to install two small VBER-300 nuclear reactors by 2015-2016 was announced in November 2007. The first was expected to be sited at Aktau, where the country's previous NPP was located.

The WEC Member Committee for Kazakhstan considers that, in local conditions, large-capacity NPPs are not appropriate: a preferred direction for power industry development would be the establishment of a regional power industry based on commercially available, reliable and safe NPPs with a capacity in the range of 100-300 MW_e. The Committee expects that reactors of this size would find a ready market in the region, as they would optimally comply with long-term development and power supply needs, and provide a perfect match with the capacity range of the fossil-fuel power plants that will in due course need to be replaced as a result of resource depletion. The joint-venture project for the VBER-300 reactor at Aktau benefits from Kazakhstan and Russia's many years' experience in designing, manufacturing and maintaining marine nuclear installations (ships and submarines) and modern NPPs.

Korea (Democratic People's Republic)

No. of reactors in operation Capacity MWe	0
No. of reactors under construction Capacity MWe	0
Net generation in 2011, TWh	0
Nuclear share of electricity generation	**0%**

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)

Korea has 23 nuclear reactors (19 PWRs and 4 PHWRs) in operation, with a reported aggregate net capacity of 20 7180 MW_e. Nuclear power makes a substantial contribution to Korea's energy supply, providing 30% of its electricity in 2011.

Three more reactors were under construction at the end of 2011. Previously the WEC Member Committee for the Korea Republic had reported that the National Energy Committee has announced 'The 1st National Energy Basic Plan', which defines the long-term strategy for the Korean energy industry over the coming twenty years and stresses the importance of nuclear power. By 2030, nuclear power will account for 41% of total generating plants and 59% of overall generating capacity. The Government is encouraging strategic partnerships and the development of next-generation reactors, in order to foster the growth of nuclear power as an export industry.

Following the sale of four NPPs to the UAE at the end of 2009, the Republic of Korea's Ministry of Knowledge Economy declared that its aim was to promote the export of 80 NPPs worth US$400 billion by 2030, and for the country to become the world's third largest supplier of power reactors.

No. of reactors in operation Capacity MWe	23 20 718
No. of reactors under construction Capacity MWe	3 3 600
Net generation in 2011, TWh	99
Nuclear share of electricity generation	**30%**

Lithuania

No. of reactors in operation Capacity MWe	0
No. of reactors under construction Capacity MWe	0
Net generation in 2011, TWh	0
Nuclear share of electricity generation	**0%**

Lithuania shut down its last nuclear reactor, which had been generating 70% of its electricity, at the end of 2009. Until then electricity was a major export for Lithuania. A new nuclear plant is planned to be built by GE Hitachi, based on a financial arrangement using vendor equity with participation of the other Baltic states. However, a 2012 referendum has introduced some uncertainty into these plans.

During the last year of two reactors being online, the country's nuclear industry produced 13.9 billion kWh out of a total 19.3 billion kWh. In the northeast of the country, Lithuania hosted the two largest Russian reactors of the RBMK type. These Ignalina reactors were originally 1500 MWe units (1380 MWe net), but were later de-rated to 1300 MWe (1185 MWe net). One of them came online at the end of 1983 (unit 1) and the second reactor was commissioned in 1987 (unit 2), with a 30-year design life. Lithuania assumed ownership of them in 1991 after the collapse of the Soviet Union. They are light-water, graphite-moderated types, similar to those at Chernobyl in the Ukraine. Construction on a third reactor at Ignalina commenced in 1985 but was suspended after the 1986 Chernobyl accident, and the unit was later demolished.

The National Energy Strategy approved by the Seimas in 2007 states that taking into consideration energy security issues and the possibility of using the existing infrastructure at Ignalina, new NPP capacity will be commissioned in Lithuania. Construction of the new plant would avoid heavy dependence on imports of fossil fuels, reduce pollution and possibly mitigate related economic consequences. Currently it is planned to commission the new unit in 2019. It is expected that decisions on the particular type of technology to be employed and the capacity of the NPP and its units, as well as on a timetable for project implementation, will be made in the near future.

The Ministry of Environment gave its approval in May 2009 to plans to build an NPP of up to 3 400 MWe capacity at Visaginas, close to Lithuania's borders with Latvia and Belarus.

Mexico

No. of reactors in operation Capacity MWe	2 1 365
No. of reactors under construction Capacity MWe	
Net generation in 2011, TWh	10
Nuclear share of electricity generation	**4%**

Mexico has two nuclear reactors which generate almost 4% of its electricity. Its first commercial nuclear power reactor began operating in 1989. There is some government support for expanding nuclear energy to reduce reliance on natural gas, but recent low gas prices have made this less of a priority.

Mexico is rich in hydrocarbon resources and is a net energy exporter. The country's interest in nuclear energy is rooted in the need to reduce its reliance on these sources of energy. In the next few years Mexico will increasingly rely on natural gas, and this is central in the new 2012 energy policy. The Federal Electricity Commission (CFE) planned to invest US$4.9 billion in 2011 andUS$6.7 billion in 2012 in new gas-fired plant and converting coal plants to gas. In addition it is calling for tenders to build three major natural gas pipelines.

There is a single nuclear power station with two BWR units of total net capacity 1 300 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 accounts for 4.8% of Mexico's total net generation. 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.

Of total 62 GWe capacity in 2010, nuclear was 1.37 GWe (gross), hydro 11.2 GWe, geothermal 970 MWe and the balance fossil fuels. Capacity is projected to increase to 86 GWe by 2025.

Netherlands

No. of reactors in operation	1
Capacity MWe	482
No. of reactors under construction	
Capacity MWe	
Net generation in 2011, TWh	4
Nuclear share of electricity generation	**4%**

Nuclear power has a small role in the Dutch electricity supply, with the Borssele reactor providing about 4% of total generation - 4.1 billion kWh in 2011. It began operating in 1973. Initially, 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 (on line from 1973). Borssele's output accounts for 3.7% of Dutch electricity generation. 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 482 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.

In June 2009 the Dutch utility Delta began a process designed to lead to an application to build an NPP, to be operating by 2018. Public and political support is increasing for expanding nuclear energy.

Nigeria

No. of reactors in operation Capacity MWe	0
No. of reactors under construction Capacity MWe	0
Net generation in 2011, TWh	0
Nuclear share of electricity generation	**0%**

The Federal Government has approved the technical framework for fast-tracking the deployment of NPPs in Nigeria. The country's nuclear roadmap envisages the installation of 1 000 MW_e by 2017 and 4 000 MW_e by 2027.

In March 2009 Russia and Nigeria agreed to cooperate on the peaceful use of nuclear energy, including the construction of NPPs.

Pakistan

No. of reactors in operation Capacity MWe	2 425
No. of reactors under construction Capacity MWe	1 300
Net generation in 2011, TWh	5
Nuclear share of electricity generation	**5%**

Pakistan has a small nuclear power programme, with 725 MWe capacity, but plans to increase this substantially. Pakistan's nuclear weapons capabilities have been developed independently of the civil nuclear fuel cycle using indigenous uranium. Since Pakistan is outside the Nuclear Non-Proliferation Treaty, due to its weapons programme, it is largely excluded from trade in nuclear plant or materials, which hinders its development of civil nuclear energy.

In 2010 Pakistan produced 94.5 billion kWh of electricity, 33 TWh of this from oil, 26 from natural gas and 32 from hydro. Nuclear power makes a small contribution to total electricity production supplying only 5.2 TWh (5% of the electricity in 2011). In 2005 an Energy Security Plan was adopted by the government, calling for a huge increase in generating capacity to more than 160 GWe by 2030. Significant power shortages are reported, and load shedding is common.

Philippines

No. of reactors in operation Capacity MWe	
No. of reactors under construction Capacity MWe	0
Net generation in 2011, TWh	0
Nuclear share of electricity generation	**0%**

After a government decision in 2007 to re-examine the scope for using nuclear power in the Philippines, the feasibility of rehabilitating the mothballed Bataan NPP was examined by an IAEA team early in the following year. The Korean Republic has reportedly also offered assistance.

Poland

No. of reactors in operation Capacity MWe	0
No. of reactors under construction Capacity MWe	0
Net generation in 2011, TWh	0
Nuclear share of electricity generation	**0%**

Poland plans to have nuclear power from about 2025 as part of its energy portfolio diversification, moving it away from heavy dependence on coal and imported gas. The nuclear plant will be a joint venture of three utilities and a copper mine all state-owned. It was earlier planned to have a stake in the new Visaginas nuclear power plant in Lithuania.

In 2011, Poland produced some 163 billion kWh gross from 33 GWe installed capacity of mostly coal plant. Coal provided 141 TWh (86.5%) of the electricity, gas 5.8 TWh (3.5%), biofuels 7.9 TWh (4.8%) and wind 2.7 TWh (1.6%). Net exports were 1.4 billion kWh.

Romania

No. of reactors in operation Capacity MWe	2 1 300
No. of reactors under construction Capacity MWe	0
Net generation in 2011, TWh	12
Nuclear share of electricity generation	**20%**

Romania has two nuclear reactors generating almost 20% of its electricity. The first commercial nuclear power reactor began operation in 1996. Its second started up in May 2007. Plans are well advanced for completing two more units, but finance has not been arranged. Romanian government support for nuclear energy is strong. Nuclear energy now provides 10% of the electricity at very low cost, only hydro (29% of supply) is cheaper. In 2006, 40% of electricity was generated from coal, 19% from gas, 29% from hydro and 9% from nuclear. In 2007 13% was from nuclear, with unit 2 of Cernavoda coming on line.

Romania's first nuclear plant - a PHWR supplied by AECL of Canada, with a current net capacity of 655 MW_e - came on line in 1996 at Cernavoda in the east of the republic. Cernavoda-2 entered commercial service in October 2007, having achieved grid connection on 7 August. The Cernavoda NPP was designed for five reactors, using Canadian CANDU-type technology. While completion of the third and fourth units is being planned, there appear to be no plans to construct the fifth unit.

In February 2010 it was announced that the Romanian power company EnergoNuclear and AECL had signed a contract for the Canadian company to assess the technical and commercial viability, and planning of Cernovada-3 and -4, in order to define what is required to complete the project.

Russian Federation

No. of reactors in operation Capacity MWe	33 23 643
No. of reactors under construction Capacity MWe	9 6 500
Net generation in 2011, TWh	166
Nuclear share of electricity generation	**18%**

Russia is moving steadily forward with plans for a much expanded role for nuclear energy, with 50% increase in output by 2020. Efficiency of nuclear generation in Russia has increased dramatically since the mid-1990s. Exports of nuclear goods and services are a major Russian policy and economic objective. Technologically, Russian reactor designs are well advanced and the country is a world leader in fast neutron reactor technology.

Russia's first nuclear power plant, and the first in the world to produce electricity, was the 5 MWe Obninsk reactor, in 1954. Russia's first two commercial-scale nuclear power plants started up in 1963-64, then in 1971-73 the first of today's production models were commissioned. By the mid 1980s Russia had 25 power reactors in operation, but the nuclear industry was beset by problems. The Chernobyl accident led to a resolution of these.

There are 33 nuclear units installed at ten different sites at the end of 2009, 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 WWEfour 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 18% of the Russian Federation's electricity output in 2009.

Site licences were issued in November 2009 for the Seversk nuclear co-generation plant in the Tomsk Oblast, Siberia. The containment dome at Kalinin 4 was installed in December 2009. It was reported in March 2010 that Volgodonsk 2, near Rostov, had been synchronised with the regional power grid and would enter commercial operation later in the year.

Rosenergoatom is the only Russian utility operating nuclear power plants. Its ten nuclear plants have the status of branches. It was established in 1992 and was reconstituted as a utility in 2001.

In February 2010 the government approved the federal target program designed to bring a new technology platform for the nuclear power industry based on fast reactors. Rosatom's long-term strategy up to 2050 involves moving Jto inherently safe nuclear plants using fast reactors with a closed fuel cycle. It envisages nuclear providing 45-50% of electricity at that time, with the share rising to 70-80% by the end of the century. In June 2010 the government approved plans for 173 GWe of new generating capacity by 2030, 43.4 GWe of this being nuclear.

Slovakia

No. of reactors in operation Capacity MWe	4 1 816
No. of reactors under construction Capacity MWe	2
Net generation in 2011, TWh	15
Nuclear share of electricity generation	**54%**

Slovakia has four nuclear reactors generating half of its electricity and two more under construction. Slovakia's first commercial nuclear power reactor began operating in 1972. Government commitment to the future of nuclear energy is strong.

Electricity consumption in Slovakia has been fairly steady since 1990[a]. Generating capacity in 2010 was 7.9 GWe, almost one quarter of this nuclear[b]. In 2011, 26 billion kWh gross was produced, 15.4 TWh (55%) of this from nuclear power, with hydro 4.1 TWh (16%), coal 4.1 TWh (16%) and gas 2.2 TWh (8.5%) also. Net imports were 0.7 TWh. Slovakia has gone from being a net exporter of electricity – of some 1 billion kWh/yr – to being a net importer following the shutdown of the Bohunice V1 reactors[c].

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 was withdrawn from service at the end of 2008. The remaining four reactors are reported to have a current net capacity of 1 711 MW_e and to have provided 53.5% of the republic's electricity output in 2009.

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Slovenia

No. of reactors in operation Capacity MWe	1 688
No. of reactors under construction Capacity MWe	
Net generation in 2011, TWh	1
Nuclear share of electricity generation	**38.5%**

Slovenia has shared a nuclear power reactor with Croatia since 1981. A bi-national PWR (current capacity 666 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 37.8% of Slovenia's net electricity generation in 2009. According to the Slovenian WEC Member Committee Krsko will operate till 2023, with possible extension.

Electricity production in Slovenia in 2011 was 16.1 billion kWh gross, and after net exports of 1.3 billion kWh, final consumption was 12 billion kWh. Nuclear power from the single reactor supplied 6.2 TWh (38.5%) of the country's electricity in 2011, coal provided 5.3 TWh (33%) and hydro 3.7 TWh (23%). NPP Krsko supplied a record 5.8 billion kWh in 2008, split equally between Slovenia and Croatia.

South Africa

No. of reactors in operation Capacity MWe	2 1 860
No. of reactors under construction Capacity MWe	0
Net generation in 2011, TWh	2
Nuclear share of electricity generation	**5%**

South Africa has two nuclear reactors generating 5% of its electricity. South Africa's first commercial nuclear power reactor began operating in 1984. Government commitment to the future of nuclear energy is strong, with firm plans for further 9600 MWe in the next decade, but financial constraints are severe. Construction of a demonstration Pebble Bed Modular Reactor has been cancelled.

In 2008, Eskom power stations produced 230.0 billion kWh (TWh) of electricity (out of total South African electricity production of 239.5 TWh), of which the Koeberg nuclear plant generated 12.7 TWh – about 5.3% of total South African generation.

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 nearly 5% of South Africa's electricity in 2009. Nuclear fuel is procured and delivered to the Koeberg NPP in accordance with government-authorised contracts for the supply of enriched uranium and for the supply of fabrication services for the nuclear fuel assemblies. Development of the pebble bed modular reactor (PBMR) concept, which is based on a number of small reactors operating in tandem, has been undertaken in South Africa for a number of years, but now appears to be in jeopardy.

In the May 2011 budget speech the energy minister reaffirmed that 22% of new generating capacity by 2030 would be nuclear and 14% coal-fired. The budget also provided R586 million ($85 million) for the Nuclear Energy Corporation of South Africa (NECSA) "to continue with its central role as the anchor for nuclear energy research and development and innovation."

Spain

No. of reactors in operation	7
Capacity MWe	7 112
No. of reactors under construction	0
Capacity MWe	
Net generation in 2011, TWh	58
Nuclear share of electricity generation	**21%**

Spain has seven nuclear reactors generating a fifth of its electricity. Its first commercial nuclear power reactor began operating in 1968. There are plans for renewed uranium mining. Government commitment to the future of nuclear energy in Spain has been uncertain, but has firmed up as the cost of subsidising renewables becomes unaffordable.

Nine nuclear reactors were brought into commission between 1968 and 1988. José Cabrera-1 (Zorita-1), Spain's oldest NPP (142 MW_e), was permanently shut down on 30 April 2006 after 38 years in operation. It had previously been scheduled for closure in 2008, but in 2004 the Government decided to close it two years earlier.The remaining eight reactors had an aggregate net capacity of 7 450 MW_e and in that year provided 17.5% of Spain's electricity generation. Two of the units are BWRs (total capacity 1 510 MW_e), the rest being PWRs. The Garoña NPP (a 446 MW_e BWR) was granted a four-year life extension in July 2009.

Sweden

No. of reactors in operation Capacity MWe	10 9 395
No. of reactors under construction Capacity MWe	0
Net generation in 2011, TWh	61
Nuclear share of electricity generation	**40%**

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-2009 had an aggregate net capacity of 8 958 MW_e. Nuclear power provided 42% of Sweden's net output of electricity in 2008, but its share fell to 37.4% the following year.

Sweden's coalition government annulled the country's anti-nuclear policies early in 2009. In May of the same year approval was given for increasing the thermal output of Ringhals 3 by 5%, and test operation of the uprated unit for one year was sanctioned in the following October.

It was announced in June 2009 that the world's first permanent disposal site for used nuclear fuel would be constructed at Forsmark in eastern Sweden, with site works possibly beginning in 2013.

A capacity expansion of almost 38% for Unit 2 of the Oskarshamn NPP received government approval in April 2010.

Sweden's nuclear capacity at end-2020 is forecast by the WEC Member Committee to total 10 000 MW_e from 10 units, implying that an overall increase of around 1 062 MW_e (or 11.9%) is obtained as a result of uprating existing reactors during the years 2009-2020, assuming that no new reactors are brought into service in this period.

Switzerland

No. of reactors in operation Capacity MWe	5 3 263
No. of reactors under construction Capacity MWe	0
Net generation in 2011, TWh	26
Nuclear share of electricity generation	**40%**

Switzerland has 5 nuclear reactors generating 40% of its electricity. Two large new units were planned. A national vote had confirmed nuclear energy as part of Switzerland's electricity mix. However, in June 2011 parliament resolved not to replace any reactors, and hence to phase out nuclear power by 2034.

In 2011 electricity production was 64.5 billion kWh gross, mostly from nuclear and hydro. A lot of electricity is imported from France, Austria and Germany and up to 26 TWh/yr exported to Italy, with exports and imports largely balanced. In 2011 nuclear power contributed 25.6 TWh, 40.6% of Swiss total production, with hydro supplying 53%.

The Swiss WEC Member Committee reports that decommissioning of the three oldest NPPs, 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 gradually expire in the second half of the next decade. Replacement of this capacity will provide a major challenge for Swiss energy policy in the coming years.

Three general licence applications for new NPPs (at the existing sites of Beznau, Gösgen and Mühleberg) have been filed by the three main Swiss utilities. The Nuclear Energy Law of 2005 requires general licences for NPPs to be voted by Parliament. Under Swiss legislation, parliamentary decisions can be challenged in a popular referendum. Public opinion is currently split into two equal camps of pros and cons. Opponents have announced that they would launch a referendum against any parliamentary approval of general NPP licences. This is expected to occur around 2013/14. Meanwhile, efforts are under way to form a consortium among the utilities so as to reduce the licence applications to two, since three applications slow down licensing procedures and mobilise opposition, given that the country will need only one or possibly two NPPs in the future.

Turkey

No. of reactors in operation Capacity MWe	0
No. of reactors under construction Capacity MWe	0
Net generation in 2011, TWh	0
Nuclear share of electricity generation	**0%**

Turkey has had plans for establishing nuclear power generation since 1970. Today, plans for nuclear power are a key aspect of the country's aim for economic growth. Recent developments have seen Russia take a leading role in offering to finance and build 4800 MWe of nuclear capacity. Application has been made for construction and operating licences for the first plant, at Akkuyu, and these are expected in mid 2014. A Franco-Japanese consortium is to build the second nuclear plant, at Sinop. Turkey imports much of its energy, and in 2012 this amounted to more than $60 billion. Improving energy efficiency and energy security are high priorities.

Plans for nuclear power are a key aspect of the country's aim for economic growth, and it aims to cut back its vulnerable reliance on Russian and Iranian gas for electricity. The Ministry of Energy and Natural Resources (ETKB) projects 2020 electricity production as possibly 499 TWh in a high scenario of 8% growth, or 406 TWh with a low one with 6.1% growth.

Ukraine

No. of reactors in operation Capacity MWe	15 13 107
No. of reactors under construction Capacity MWe	2 1 900
Net generation in 2011, TWh	78
Nuclear share of electricity generation	**49%**

Ukraine is heavily dependent on nuclear energy - it has 15 reactors generating about half of its electricity. Ukraine receives most of its nuclear services and nuclear fuel from Russia. In 2004 Ukraine commissioned two large new reactors. The government plans to maintain nuclear share in electricity production to 2030, which will involve substantial new build.

A large share of primary energy supply in Ukraine comes from the country's uranium and substantial coal resources. The remainder is oil and gas, mostly imported from Russia. In 1991, due to breakdown of the Soviet Union, the country's economy collapsed and its electricity consumption declined dramatically from 296 billion kWh in 1990 to 170 in 2000, the decrease coming mainly from coal and gas plants. Today Ukraine is developing shale gas deposits and hoping to export this to western Europe by 2020 through the established pipeline infrastructure crossing its territory from the east.

A major increase in electricity demand to 307 billion kWh per year by 2020 and 420 billion kWh by 2030 is envisaged, and government policy was to continue supplying half of this from nuclear power. This would have required 29.5 GWe of nuclear capacity in 2030, up from 13.9 GWe (13.2 GWe net) now.

In mid 2011 the Ukraine energy strategy to 2030 was updated, and in the electricity sector nuclear power's role was emphasized, with improved safety and increased domestic fuel fabrication. In mid 2012 the policy was gain updated, and 5000 to 7000 MWe of new nuclear capacity was proposed by 2030, costing some US$25 billion.

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.

United Arab Emirates

No. of reactors in operation Capacity MWe	0
No. of reactors under construction Capacity MWe	0
Net generation in 2011, TWh	0
Nuclear share of electricity generation	**0%**

The UAE is taking deliberate steps in close consultation with the International Atomic Energy Agency to embark upon a nuclear power programme. It accepted a $20 billion bid from a South Korean consortium to build four commercial nuclear power reactors, total 5.6 GWe, by 2020. Construction of the first unit started in July 2012.

In April 2008 the Government of the UAE published a comprehensive national policy on nuclear energy, which envisaged the eventual installation of a series of NPPs in the Emirates. In May of the following year President Obama approved a nuclear energy cooperation agreement between the USA and the UAE. By October the latter had established a national nuclear regulatory authority, whilst at the end of the year it was reported that the UAE had selected Korean Republic companies to lead the construction of four APR1400 reactors. In April 2010, the preferred site of the first NPP to be constructed in the Emirates was reported to be Braka, 53 km west of Ruwais. Construction is planned to begin in late 2012, with commercial operation of the first two units envisaged for 2017-2018, followed by units 3 and 4 in 2019-2020.

United Kingdom

No. of reactors in operation Capacity MWe	16 9 243
No. of reactors under construction Capacity MWe	0
Net generation in 2011, TWh	56
Nuclear share of electricity generation	**18%**

The UK has 16 reactors generating about 19% of its electricity and all but one of these are due to be retired by 2023. EDF intends to build four new EPR reactors (each of around 1.6 GW_e) by 2025, with the first one operational by the end of 2017. RWE and E.ON have announced a joint venture with an objective of delivering at least 6 GW_e of new NPPs, with the first station coming on line at around the end of the next decade.

The country has full fuel cycle facilities including major reprocessing plants. The UK has implemented a very thorough assessment process for new reactor designs and their siting.The first of some 19 GWe of new-generation plants are expected to be on line about 2018. The government aims to have 16 GWe of new nuclear capacity on line by 2030.

In the late 1990s, nuclear power plants contributed around 25% of total annual electricity generation in the UK, but this has gradually declined as old plants have been shut down and ageing-related problems affect plant availability. Net electricity imports from France – mostly nuclear – in 2011 were 6.2 billion kWh, less than 2% of overall supply.

The Government is currently preparing a draft National Policy Statement for nuclear power. This will set out the national need for new nuclear power, and include a draft list of sites that the Government has judged to be potentially suitable for the deployment of new NPPs by the end of 2025. Subject to public consultation and Parliamentary scrutiny, the National Policy Statement would be used by the new Infrastructure Planning Commission when it makes decisions on applications for development consent for new NPPs.

The Government expects the first new nuclear power station to be operational from around 2018.

United States of America

No. of reactors in operation Capacity MWe	100 98 903
No. of reactors under construction Capacity MWe	3 1 165
Net generation in 2011, TWh	799
Nuclear share of electricity generation	**19%**

The USA is the world's largest producer of nuclear power, accounting for more than 30% of worldwide nuclear generation of electricity. The country's 104 nuclear reactors produced 821 billion kWh in 2011, over 19% of total electrical output. There are now 103 units operable and three under construction. Following a 30-year period in which few new reactors were built, it is expected that 4-6 new units may come on line by 2020, the first of those resulting from 16 licence applications made since mid-2007 to build 24 new nuclear reactors. However, lower gas prices since 2009 have put the economic viability of some of these projects in doubt.

Government policy changes since the late 1990s have helped pave the way for significant growth in nuclear capacity. Government and industry are working closely on expedited approval for construction and new plant designs.

The USA has 103 nuclear power reactors in 31 states, operated by 30 different power companies. Since 2001 these plants have achieved an average capacity factor of over 90%, generating up to 807 billion kWh per year and accounting for 20% of total electricity generated. Capacity factor has risen from 50% in the early 1970s, to 70% in 1991, and it passed 90% in 2002, remaining at around this level since. The industry invests about $7.5 billion per year in maintenance and upgrades of these reactors.

There are 68 pressurized water reactors (PWRs) with combined capacity of about 66 GWe and 35 boiling water reactors (BWRs) with combined capacity of about 34 GWe – for a total capacity of 101,355 MWe (see Nuclear Power in the USA Appendix 1: US Operating Nuclear Reactors). Almost all the US nuclear generating capacity comes from reactors built between 1967 and 1990. There have been no new construction starts since 1977, largely because for a number of years gas generation was considered more economically attractive and because construction schedules were frequently extended by opposition, compounded by heightened safety fears following the Three Mile Island accident in 1979. A further PWR – Watts Bar 2 – is expected to start up in 2015 following Tennessee Valley Authority's (TVA's) decision in 2007 to complete the construction of the unit.

5

Hydro

Contents

Strategic insight

1. Introduction and Global Status

Hydropower provides a significant amount of energy throughout the world. There has been deployment in more than 100 countries, contributing approximately 15% of the global electricity production.

The top 5 largest markets for hydropower in terms of capacity are China, Brazil, the United States, Russia, and Canada, with China far exceeding the others at 249GW. Added to these, India, Norway, Japan, France and Turkey complete the top 10 countries in terms of capacity.

In addition, in several countries, hydropower accounts for over 50% of all electricity generation including: Iceland, Brazil, Canada, Nepal and Mozambique.

During 2012, an estimated 27-30GW of new hydropower and 2-3GW of pumped storage hydropower was commissioned during the year. In many cases, this development was accompanied by renewable energy support policies and current and planned regional carbon markets.

Global growth in installed capacity of hydropower has been concentrated in the emerging markets in Asia and South America, where increased access to electricity is and improved reliability are major requirements to support rapid economic development. This trend is most visible in China where over 15GW was deployed in 2012. China expects this growth to continue through 2015 to 284 GW to meet the requirements of the 12th 5- year plan. It is also expected that China will see pumped storage capacity grow to 41GW during this period. If China reaches the goals in its 5 year plan reports indicate it will be exploiting 71% of its available hydroelectric power.

In recent years, the increasing demand for the security of supply of both water and energy continues to drive hydropower development on a regional basis. Hydropower operators are seeing increased trans-boundary collaboration in the development and operation of hydropower projects, and in regional interconnections to enable the cross-border sale of the resulting electricity. In many cases, this cooperation brings benefits in terms of improved energy access in one or more country, economic opportunities, and improved water services.

In addition, the tremendous advances in wind and solar power deployment in many countries have changed the energy mix substantially, and this trend is clearly set to continue. This development is having a profound impact on how existing hydropower stations are operated and modernized, and how new hydropower stations are designed.

Policy

Hydropower development is in many cases supported by renewable energy policies. This support can be either direct – where hydropower qualifies for a feed-in-tariff or is an eligible technology under a renewable portfolio standard; or indirect – where hydropower development is spurred by the increased penetration of other renewables that are eligible for this kind of policy/financial support.

Carbon markets also continue to influence hydropower deployment, particularly in developing countries. The UN FCC Clean Development Mechanism (CDM)and the EU Emissions Trading Scheme (ETS) are the most prominent players in this area. The CDM is an implementing mechanism of the Kyoto Protocol, where projects can be registered to receive and sell Certified Emissions Reductions certifications. As of 5 March 2013, of the 8,013 renewables projects active in the CDM pipeline, 2,899 are hydropower projects with a potential combined installed capacity of 138GW.

CDM projects have historically been concentrated in China and India, with those two countries accounting for 80% of CDM credits issued to date. However, new host countries in 2012 were Albania, Cambodia, Georgia, Kenya, Lao PDR, Macedonia, and Nicaragua. In 2012-13 the UN also opened two collaboration centres in Africa to encourage further update of CDM projects on the continent.

The EU ETS is the world's largest carbon market, established by the EU to help meet its Kyoto Protocol targets. The EU ETS purchases the vast majority of CERs issued under the CDM. However, other countries currently working towards establishment of a carbon market are California, Australia, Canada and Japan. The World Bank is also providing support to exploration of carbon markets in Brazil, Mexico, Colombia, Thailand, Vietnam, and South Africa.

Other policies relevant to hydropower at a domestic level include water policies, energy regulatory policies, and environmental and social regulation.

2. Technical and economic considerations

Technology

Hydropower – harnessing the energy of moving water for power - has been in use since ancient times. However, the turbine technology as well as developments in design and construction techniques have advanced significantly and continue to do so today.

There are four broad hydropower typologies:

- Run-of-river hydropower – provides regular base-load supply, with some flexibility of operation for daily fluctuations in demand through water flow that is regulated by the facility)
- Storage hydropower – provides base- and peak-load supply, with enough storage capacity to operate independently of the hydrological inflow for periods of weeks/months, and the ability for generation to be shut down and started up at short notice)
- Pumped-storage hydropower – provides peak-load supply, utilizing water which is cycled between lower and upper reservoirs by pumps which utilize surplus energy from the system at times of low demand, normally on a daily/weekly basis).
- Offshore hydropower – a suite of technologies using basic hydropower technology in a marine environment. This includes wave and tidal technologies.

However, the boundaries between these types of hydropower are not concrete; for example, storage projects may incorporate a component of pumping to supplement the water that flows into the upper reservoir naturally. Run-of-river projects may benefit from greater flow regulation (generation flexibility) from a storage project located upstream. Run-of-river projects may also incorporate a few hours up to a few days of storage capability. There is no standard that completely differentiates each typology from the others, but in general these typologies represent the hydropower sector.

Outside of ocean hydropower, with regard to turbine types, there are two main categories: reaction and impulse. Impulse turbines utilize the pressure of the water column falling on the turbine through a concentrated jet. For maximum efficiency, the direction of the water striking the turbine is turned through 180°, and then falls to a tail-water channel which is open to the atmosphere. Reaction machines utilize both the pressure of the water entering the turbine and the suction of the water exiting the turbine through a draft-tube passageway, while flowing towards the downstream water body.

Examples of impulse turbines are Pelton type units; these tend to be used at sites when the available head at the site is very high and the discharge is small. Reaction turbines tend to be used when the ratio between head and discharge moves towards lower available head with higher flows. Moving from higher to lower head, examples are Francis, Kaplan and Bulb type turbines.

All the above turbine types are at advanced echelons of technical design. Consequently, extraordinary levels of efficiency can now be expected. Modern hydropower turbines can achieve efficiencies of 95% across their operating range (design limits of head/discharge) – something unparalleled in any other turbine technology. Efficiency gains and the trend for higher capacity equipment to provide peaking generation, continue to drive the market for the modernization of power stations throughout the world. The upgrading and replacement of turbine equipment at existing stations currently represents about 15% of the investment in the hydropower sector. This proportion is likely to remain constant, but will grow in absolute terms as the world's fleet of hydropower stations continues to increase (currently estimated to be about 15,000 in total).

Nonetheless, hydropower technology is regularly refined to optimize performance and minimize local impacts. Recent advances in hydropower technology include ongoing improvement and increased deployment of tidal hydropower; technological refinements to turbine operations to enable rapid ramp up and ramp down to accommodate increased penetration of renewables into electricity systems (i.e., more variable sources of energy in an electricity system require a technology such as storage or pumped storage hydropower to balance that variability); improved pumping technology for pumped storage hydropower; and fish-friendly infrastructure. For example, ongoing developments with variable speed pumps in pumped storage stations will help enable penetration of more variable renewable energy sources. In addition, technological advances have the potential to improve the environmental performance of hydropower. For example, the US Electric Power Research Institute (EPRI) is currently undertaking research both in the area of development of fish-friendly hydropower turbines that cause minimal injury to passing fish and in the collection of more general information on fish behavior at passages and ladders, and the effectiveness of such measures.

With regard to scale, all the above turbine types can be utilized at sites from the very smallest through the largest capacities. A Francis type turbine, for example, can be used at sites to generate less than 0.1MW through to 800MW. The basic turbine would look exactly the same; the only difference would be the dimensions.

As a growing number of low-head sites are being exploited, the number of Bulb type turbine applications is increasing. For example, on the Madeira River in Brazil, two power plants are under construction: the Santo Antônio and Jirau projects. Each will utilize 44 Bulb turbines – an unprecedented number of turbines in single power stations. The projects will add more than 6000MW capacity to the Brazilian electricity system, enough to power two cities the size of São Paulo.

Sustainability

Water use for energy, hydropower in particular, is important throughout the world. The specific characteristics of hydropower are fundamental for the balancing of supply and demand in electric power systems. In particular, the supportive role of hydropower in backing up the growing contribution from wind and solar is essential for security of supply. Hydropower's ability to store both water and energy is also increasingly valued. Despite the long history of hydropower development, record levels of deployment have occurred in the last five years. Notwithstanding this, sustainable development in the context of hydropower has been the subject of debate. Today, a broad consensus on basic good practice exists, which has been developed through multi-stakeholder processes, and tools are available for the measurement of sustainability in the hydropower sector. The following describes some of the hydropower-specific sustainability aspects.

- The potential impacts of hydropower projects are well documented[1], for example:
  - Hydrological regimes;
  - Land-use change;
  - Water quality;
  - Sediment transport;
  - Biological diversity;
  - Resettlement; Downstream water users;
  - Public health;
  - Cultural heritage.

- The gravity of the particular negative impacts varies from project to project, as does the scope for their avoidance or mitigation. Also, the opportunity to maximize positive impacts (beyond the renewable electricity generated) varies from site to site.

- Tools, such as the IFC Performance standards, World Bank Safeguards, and the Equator Principles, have all contributed to increased awareness of the need to balance technical and economic benefits with protecting environmental and social outcomes. The Hydropower Sustainability Assessment Protocol, a hydropower-specific tool, provides a means of measuring a project's performance throughout project's life-cycle, across all aspects of sustainability. This tool is the result of a multi-stakeholder process with the objective of guiding sustainability in the hydropower sector, and is currently being implemented worldwide (www.hydrosustainability.org).

- Increasingly, hydropower developers and owners are using tools such as the Protocol to guide project decision-making, implementation and operation. As a growing hydropower practice, the sustainability benefits are considerable: besides environmental and social issues being treated with parity to other considerations, such tools ensure that international practices are applied locally irrespective of variations in national regula-

1. IPCC SRREN, Chapter 5Kumar, A., T. Schei, A. Ahenkorah, R. Caceres Rodriguez, J.-M. Devernay, M. Freitas, D. Hall, A. Killingtveit,Z. Liu, 2011: Hydropower. In IPCC Special Report on Renewable Energy Sources and Climate Change Mitigation [O. Edenhofer, R. Pichs-Madruga, Y. Sokona, K. Seyboth, P. Matschoss, S. Kadner, T. Zwickel, P. Eickemeier, G. Hansen, S. Schlomer, C. von Stechow (eds)], Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA, at 463, citing IEA, 2000a,b,c,d,e.

tions, and provide common frameworks around which project stakeholders can engage in dialogue around specific projects and their impacts.

- Some examples of how specific impacts are being addressed include:
  - An increased awareness of the need to identify projects with a strategic fit in a national or regional context, and the use of offsets to compensate for a biodiversity impact. This ranges from identification of no-go project areas to the protection of other areas to compensate for project impacts.
  - In depth interaction with project affected communities, including Indigenous people, is moving from impact mitigation and compensation to benefit sharing and livelihood improvement through long term collaborative initiatives. This includes increased recognition of risks and identification of opportunities to avoid or mitigate negative aspects, and to optimize positive impacts through committed engagement with the affected community. Where resettlement is unavoidable, community-led decision-making on plans made in partnership with the developer is increasingly being used to address this most challenging of impacts.
  - Greater understanding of environmental flows and the impacts of changes to these flows has moved consideration from revenue generation and flood control driven practises to the adoption of environmental flow policies that recognise the limitations of pre-determined minimum flows and focus on maintaining flows to support a broader spectrums of riverine species, processes and services, adapted to suit individual contexts.
  - Upstream land use is increasingly being recognized for its impacts on sedimentation issues, and land-use management practices included in reservoir management plans.

- Technological developments contributing to sustainability considerations include refined fish ladders and other effective upstream transportation options, 'fish friendly' turbines lowering downstream passage fish mortality, incorporation of generating capacity into existing storage facilities where previously there was none, and design changes to minimize or avoid lubricating oil discharges from turbine equipment. Perhaps most important, is the orientation of equipment and operations at hydropower stations, to back up the variable generation from other renewables such as wind and solar. This evolution in the role of hydropower will facilitate an even greater contribution from all renewable energy sources in the future.

3. Market trends and outlook

Markets

Hydropower development has traditionally been led by public sector developers supported at least partly by public finances, either from national governments or multilateral development banks. However, in recent years, hydropower investment is becoming increasingly global with investors exploring new regions, and a shift toward more private sector involvement in hydropower development. Examples include South Korea's investment in Nepal, Pakistan, and the Philippines, as well as China and India driving investments in Africa.

Private sector investment often enables projects to be built in a shorter timeframe, and also can enable infrastructure development in areas where local entities are unable to provide the high level of investments needed to build a hydropower facility. However, private sector investors will typically require a more solid return on investment and much stronger assurance of future sales through strong power purchase agreements with the local customer. This also shifts the responsibility for ensuring environmental and social impacts are properly mitigated and managed to the local planning agencies and regulators, who in many cases need external support for capacity building in these areas.

With regard to power pools, regional markets for electricity often support the business case for hydropower development, particularly in locations with hydropower resources and/or potential that exceed their domestic electricity demand. For example, Ethiopia has tremendous hydropower potential, but does not have sufficient domestic demand to justify its full development. Neighbouring countries Kenya and Sudan, on the other hand, do not have domestic hydropower potential and can benefit from the electricity provided by hydropower development in Ethiopia. Countries may opt to pool their investment resources to jointly develop hydropower projects such as, for example, the Governments of Burundi, Rwanda, and Tanzania under the umbrella of the Nile Basin Initiative/Nile Equatorial Lakes Subsidiary Action Program. These countries, along with the World Bank, are developing a 90-megawatt hydropower plant at a cost of 400 billion Burundian francs (USD 312 million).

In addition, regional electricity interconnections (and market structures) promote stability in the electricity system while reducing the need for costly system redundancy. Regional power pools support this trade in electricity across countries. Examples of regional power pools that are supported by hydropower assets include the Central American Electrical Interconnection System (SIEPAC), the Eastern African Power Pool (EAPP), the Southern African Power Pool (SAPP), and the European system, and several regional Canadian-US trading markets.

Traditionally, hydropower has been designed to provide steady base-load supply, with plant factors exceeding 80%. Projects with storage reservoirs can also release water in a controlled way so as to follow the demand in the electricity grid. With the increasing penetration of more variable renewable energy services, hydropower is called on to play a supportive role: starting up at short notice when there is a deficit in the power system, and shutting down when there is a surplus, rather than providing base load power. In such situations, the stations may need to be available to operate most of the time, but only utilizing energy when the demand calls for it; hence the station might be available for 90% of the time but only be needed to operate for 20% of time. This shift in the way hydropower is operated is benefited by a shift in the market dynamics and structure. Increasingly, electricity markets are incentivizing this type of flexible generation by rewarding it with much higher prices when energy is most needed, and giving a price signal to deter generation when there is a surplus in the system. However, many countries have yet to change their market structures to accommodate shifting generation patterns.

Global tables

Table 1
Hydropower capability

	Gross theoretical capability	Technically exploitable capability	Economically exploitable capability
Country	GWh/year	GWh/year	GWh/year
Angola	150000		
Argentina	U	169000	
Australia	150000		
Austria	150000	75000	56100
Bhutan	263000		
Bolivia	126000		
Brazil	3040000	1250000	817600
Bulgaria	26540	15056	NA
Cameroon		115000	
Canada	757579.60	U	U
Chile	162		
China	5920000		
Colombia	1000		
Congo (DRC)	1400		
Costa Rica	223500		
Croatia	20000	12000	10500
Czech Republic	13100	3978	NA
Ecuador	167000		106000
Estonia	2000	400	250
Ethiopia	650000		
Finland	30865	22645	16026
France		100	70
Guinea	26000		
Iceland	184000		
India	2638000		
Indonesia	2150		
Iran	179000	50000	
Italy	200000	65000	47500
Japan	U	136520	U
Kazakhstan	170000	62000	29000

Latvia	U	U	U
Lithuania	2200		
Madagascar	321		180
Malaysia	123	16	
Myanmar (Burma)		140	
Nepal			140160
Norway	22.10		
Pakistan	475		
Paraguay	111		68
Peru	260		
Poland	23000	12000	5000
Portugal	U	U	U
Romania	70000	36000	21000
Russian Federation	2295		
Serbia	27200	19447	17733
Spain	162		
Sudan	19		
Sweden	65000	35000	20000
Tajikistan	2635		
Turkey	432000	216000	170000
United Kingdom	4.10		
United States of America	2040.00		
Uruguay	32	10	
Venezuela	731		
Vietnam	300		

Table 2
Hydropower installed capacity and production in 2011

	Installed capacity	Actual generation in 2011	Capacity under construction
Country	**MW**	**GWh**	**MW**
Afghanistan	400		
Albania	1 432		
Algeria	278		
Angola	790		80
Argentina	10 025	31 847	60
Australia	7 800	12 000	80
Austria	13 200	37 701	1 000
Azerbaijan	1 020		
Bangladesh	230		
Belarus	13		
Bhutan	1 488	7 134	
Bolivia	440	2 300	800
Bosnia-Herzegovina	2 380		
Brazil	82 459	428 571	21 100
Bulgaria	2 018	2 366	

Cameroon	729	3 850	
Canada	75 104	348 110	3 720
Central African Republic	19		
Chile	5 946	24 300	342 000
China	249 000	714 000	3 833
Colombia	9 185	45 583	
Congo (DRC)	2 410		
Congo (Republic of)	89		
Costa Rica	1 510		150
Cote d'Ivoire	606		
Croatia	2 141	4 620	
Cuba	7		
Cyprus	1		
Czech Republic	1 055	2 134	
Denmark	9		
Ecuador	804		
Egypt	2 942		
El Salvador	472		
Equatorial Guinea	1		
Estonia	8	30	1
Ethiopia	663		
Finland	3 084	12 278	
France	25 332	50 300	
Gabon	170		
Georgia	2 635		
Germany	4 740		
Ghana	1 180	5 600	400
Greece	3 243		
Guinea	75		80
Hungary	51		
Iceland	1 900	12 600	
India	38 106		15 627
Indonesia	3 881	12 419	
Iran	8 746		5 083
Iraq	2 273		
Ireland	529		
Israel	7		
Italy	18 092	45 823	
Jamaica	24		
Japan	22 362	72 639	291
Jordan	12		
Kazakhstan	2 267	7 849	300
Korea (DRC)	4 780		
Korea (Republic)	1 605		
Kyrgyzstan	2 910		
Laos	700		5 361
Latvia	1 550	2 810	
Lebanon	280		
Lesotho	76		
Lithuania	101		3
Macedonia	528		29
Madagascar	124	700	
Malawi	300		

Malaysia	1 910		3 344
Mali	155		
Mauritania	30		
Mexico	11 499	35 796	750
Moldova	64		
Mongolia	28		
Montenegro	658		
Morocco	1 265		
Mozambique	107		
Myanmar (Burma)	1 541	3 900	1 500
Nepal	600		
Netherlands	37		
New Zealand	5 250		
Nicaragua	105		
Norway	1 521	6 800	1 021
Pakistan	6 481	27 700	1 600
Paraguay	8 130		
Peru	3 242		
Philippines	3 291		
Poland	940	2 331	
Portugal	5 352	12 114	1 447
Puerto Rico	85		
Romania	6 144	14 954	
Russian Federation	49 700	180 000	3 000
Rwanda	55		
Senegal	60		
Serbia	2 891	9 165	
Sierra Leone	4		
Slovakia	2 523	4 105	
Slovenia	1 253		
Somalia	5		
South Africa	661		
Spain	18 540	25 000	450
Sri Lanka	1 300		
Sudan	575		
Suriname	189		
Swaziland	61	69	
Sweden	16 197	66 000	
Switzerland	13 723	32 069	1 995
Syria	1 505		
Taiwan	1 938		
Tajikistan	5 500	11 200	
Tanzania	561		
Thailand	3 481		
Togo	66		
Tunisia	70		
Turkey	17 259	57 472	8 270
Turkmenistan	1		
Uganda	340		250
Ukraine	4 514		
United Kingdom	1 630	5 700	
United States of America	77 500	268 000	
Uruguay	1 538	6 479	

Uzbekistan	1 710		
Venezuela	14 627	86 700	
Vietnam	5 500	24 000	
Zambia	1 730		
Zimbabwe	754		
World Total	934 733	2 750 946	-

Country notes

The Country Notes on Hydropower have been compiled using the information submitted by WEC Member Committees in 2012 and various national and international reference publications and other sources, including the International Hydropower Association, *The International Journal on Hydropower & Dams*, published by Aqua~Media and other sources. Note: U stands for an unknown value.

Angola

Gross theoretical capability (TWh/yr)	150
Capacity in operation (MW)	790
Actual generation (GWh)	U
Capacity under construction (MW)	

Angola's estimated hydropower potential is 150 TWh/yr, one of the highest in Africa. However, so far only a small fraction of the country's hydro potential has been harnessed. Feasibility Studies are in progress on major hydro schemes at Lauca and Caculo-Cabaca on the Kwanza river, each with an installed capacity of 2 000 MW, and on a bi-national project at Baynes Mountain on the Cunene (see country note on Namibia).

Argentina

Gross theoretical capability (TWh/yr)	U
Capacity in operation (MW)	10 025
Actual generation (GWh)	31 847
Capacity under construction (MW)	60

Hydroelectricity is an important component of Argentina's power profile. Though hydroelectric output fluctuates and has declined in recent years, it accounts for between one-quarter and one-third of Argentina's total electricity generation. Argentina's most significant hydroelectric capacity is located in Neuquén, followed by border provinces that share hydroelectric output with surrounding countries.

Argentina and Paraguay divide power from the large Yacyreta plant, which sits astride the Paraná River (Corrientes province) with a total installed capacity of 3.1 GW. Likewise, the Salto Grande hydroelectric plant on the Uruguay River (along Entre Ríos province) has a capacity of 1.89 GW, from which output is split evenly between Argentina and Uruguay. In 2011, total hydroelectric generation was 39,339 GWh, according to CAMMESA.

The WEC Argentine Member Committee reports that there is an ongoing updating and improvement of cost-estimation procedures, the review of existing projects using consistent criteria, and the evaluation of the resource up to the level of technical and economic pre-feasibility.

The Committee also reports that Argentina possesses 75 small, mini and micro hydro plants (of up to 30 MW capacity), with an aggregate capacity of 377 MW and an annual generation equivalent to 1.6% of national electricity demand.

Australia

Gross theoretical capability (TWh/yr)	150
Capacity in operation (MW)	7 800
Actual generation (GWh)	12 000
Capacity under construction (MW)	80

Australia is the driest inhabited continent on earth, with over 80 per cent of its landmass receiving an annual average rainfall of less than 600 mm per year and 50 per cent less than 300 mm per year. There is also high variability in rainfall, evaporation rates and temperatures between years, resulting in Australia having very limited and variable surface water resources. Much of Australia's economically feasible hydro energy resource has already been harnessed.

Australia has more than 100 operating hydroelectric power stations with total installed capacity of about 7800 megawatts (MW). These are located in the areas of highest rainfall and elevation and are mostly in New South Wales (55%) and Tasmania (29%). The Snowy Mountains Hydro-electric Scheme, with a capacity of 3800MW, is Australia's largest hydro scheme and is one of the most complex integrated water and hydroelectricity schemes in the world.

The Scheme collects and stores the water that would normally flow east to the coast and diverts it through trans-mountain tunnels and power stations. The water is then released into the Murray and Murrumbidgee Rivers for irrigation. The Snowy Mountains Scheme comprises sixteen major dams, seven power stations (two of which are underground), a pumping station, 145km of inter-connected trans-mountain tunnels and 80km of aqueducts. The Snowy Mountains Hydro-electric Scheme accounts for around half of Australia's total hydroelectricity generation capacity and provides base load and peak load power to the eastern mainland grid of Australia.

Hydro energy is particularly important in Tasmania where it provides much of the state's electricity. The Tasmanian integrated hydropower scheme harnesses hydro energy from six major water catchments and involves 50 major dams, numerous lakes and 29 power stations with a total capacity of over 2600MW. The scheme provides base and peak load power to the National Electricity Market, firstly to Tasmania and then to the Australian network through Basslink, the undersea interconnector which runs under Bass Strait. There are also hydroelectricity schemes in north-east Victoria, Queensland, Western Australia, and a mini-hydroelectricity project in South Australia.

Austria

Gross theoretical capability (TWh/yr)	150
Capacity in operation (MW)	13 200
Actual generation (GWh)	37 701
Capacity under construction (MW)	1 000

Out of a total gross theoretical hydro potential of 150 TWh/yr, Austria's technically feasible potential is estimated at about 75 TWh/yr, of which 75% is considered to be economically exploitable. At present, the total installed capacity of hydro-electric power stations (excluding pumped-storage plants) is 13 200 MW; with net generation of approximately 37 TWh. Most of Austria's HPPs are of the run-of-river type.

The construction of a number of (mostly fairly small) pure hydro plants and the refurbishment/extension of some existing stations is under way or planned, but the construction of large hydro installations in Austria is currently confined to a number of pumped-storage schemes. Kops II (450 MW) was completed in 2009, while work is continuing at Limburg II, which will add 480 MW to the capacity of the Kaprun pumped-storage plant in 2012, and at Reisseck II (430 MW), part of the Reisseck-Kreuzeck hydro complex, scheduled to be completed in 2014.

Bhutan

Gross theoretical capability (TWh/yr)	263
Capacity in operation (MW)	1 488
Actual generation (GWh)	7 134
Capacity under construction (MW)	1 209

Bhutan possesses a huge hydropower resource, its gross theoretical potential being assessed at over 263 TWh/yr, with a technically feasible capability of more than 99 TWh/yr (corresponding to a potential generating capacity of around 23 500 MW). Current installed hydro capacity is 1 488 MW, having recently been augmented by the commissioning of the 1 020 MW Tala HPP, Bhutan's first bi-national project, developed in conjunction with India.

Two more hydro plants are under construction - Punatsangchhu I (1 095 MW, for completion by 2015) and Dagachhu (114 MW). A further 2 400 MW of capacity is at the planning stage, notably Punatsangchhu II (circa 1 000 MW) and Mangdechhu (circa 720 MW).

The Governments of Bhutan and India are jointly planning to construct a total of ten HPPs, with an anticipated aggregate installed capacity of 11 576 MW, for development by 2020. The programme includes a number of massive projects, the largest being the Sunkosh Reservoir (4 000 MW), Kuri Gongri (1 800 MW) and Wangchhu Reservoir (900 MW) schemes. The principal function of the bi-national plants will be to boost Bhutan's exports of electricity to India.

Bolivia

Gross theoretical capability (TWh/yr)	126
Capacity in operation (MW)	440
Actual generation (GWh)	2 300
Capacity under construction (MW)	800

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 small proportion of the total potential has been harnessed so far. The country's hydro capacity, according to OLADE, was 440 MW, with an output of about 2.3 TWh.

Hydropower & Dams World Atlas 2009 reports that 88 MW of additional hydro capacity was under construction in early 2009. A wide range (2 338-3 064 MW) is quoted for planned hydro capacity, some of which relates to projects forming part of the Rio Madeira scheme outlined below.

Bolivia is working with Brazil on a huge joint project to exploit the hydro-electric potential of the Rio Madeira complex in the Amazon region. Within this project are the 800 MW Cachuela Esperanza plant sited entirely in Bolivia and the Guajara-Mirim plant (3 000 MW) to be located on the border between the two countries.

Brazil

Gross theoretical capability(TWh/yr)	3 040
Capacity in operation (MW)	82 458
Actual generation (GWh)	428 571
Capacity under construction (MW)	21 100

Hydroelectric power is one of Brazil's principal energy assets: the country has by far the largest hydropower resources on the continent. The Brazilian WEC Member Committee reports that the gross theoretical capability is estimated to be 3 040 TWh/yr, with an economically exploitable capability of about 818 TWh/yr, of which over 45% has so far been harnessed..

According to the Member Committee, Brazil had 82 458 MW of operational hydropower capacity at the end of 2011, generating in that year 428 571 GWh of electricity. The country had 21 100 MW of additional hydro capacity under construction at the end of 2011, with an estimated annual generation of around 41 TWh. Further hydro capacity reported to be planned for future development totalled 68 000 MW, with a projected annual output of some 327 TWh.

Furthermore, small-scale hydro (since 1998, defined in Brazil as plants with a capacity of <30 MW) has an economically exploitable capability of 11 200 GWh/yr. ThJe aggregate installed capacity of small HPPs was 1 237 MW at end-2008, and they produced a total of 6 280 GWh in 2008, equivalent to just over 56% of the assessed economic potential. A total of 513 MW of small-hydro capacity is planned for future installation which, if all the plans are implemented, will add some 2.5 TWh to Brazil's electricity supply.

Cameroon

Gross theoretical capability (TWh/yr)	U
Capacity in operation (MW)	729
Actual generation (GWh)	3 850
Capacity under construction (MW)	0

The technically exploitable hydro capability (115 TWh) 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 729 MW, Cameroon's major stations are Song Loulou (installed capacity 396 MW) and Edéa (264 MW), for both of which contracts have been awarded for refurbishment. Annual hydro-electric output is about 3 850 GWh, implying a capacity factor of around 0.60.The Cameroon WEC Member Committee reported that a number of projects is being negotiated but no further details are available.

Canada

Gross theoretical capability(TWh/yr)	758
Capacity in operation (MW)	75 104
Actual generation (GWh)	348 110
Capacity under construction (MW)	3 720

Canada possesses enormous hydropower potential – the Canadian Hydropower Association assessed Canada's 'total unexploited technical hydro potential' in 2011 as 163 GW, of which over half was in Québec, Alberta and British Columbia. At the end of 2011, total installed hydroelectric capacity was 75 104 MW.

Approximately 475 hydroelectric generating plants across the country produce an average of 350 terawatt-hours per year — one terawatt-hour represents enough electricity to heat and power 40,000 houses. In 2011 the actual total generation for the year was 348 TWh.

With many rivers across the country, Canada has hydropower in all regions. The top-producing provinces are Quebec, British Columbia, Manitoba, Ontario, and Newfoundland and Labrador, with more than 95 percent of the total hydropower generation in Canada.

Canada still has immense undeveloped potential — over twice the current capacity — and all provinces and territories have some hydropower potential.

There are a number of significant hydroelectric projects under construction. In total, these projects will increase hydro generation capacity by more than 2 350 MW, with a probable annual generation of 11.15 TWh. According to Natural Resources Canada, hydro capacity reported to be in the course of planning adds up to a massive 14 500 MW, potentially supplying more than 68 TWh/yr.

The total installed capacity of small hydro plants (of <10 MW) totalled 1 001 MW, with an estimated annual generation of 4 650 GWh. Small-scale HPPs are located throughout the country, notably in British Columbia, Ontario, Québec, Nova Scotia, Newfoundland and Labrador. A total of 188 MW of additional small hydro capacity is reported as planned, with a projected generation of 873 GWh/yr.

Chile

Gross theoretical capability (TWh/yr)	162
Capacity in operation (MW)	5 946
Actual generation (GWh)	24 300
Capacity under construction (MW)	0

There is a substantial hydropower potential, with a technically exploitable capability estimated at about 162 TWh/yr, of which about 15% has so far been harnessed. Hydro output in 2011 was 24.3 TWh, equivalent to just over 40% of Chile's total net electricity generation.

More than 5 800 MW of new HPPs is at the planning stage, including major projects at Alto Maipo (531 MW), Angostura (309 MW), Neltume and Choshuenco (580 MW) and Rio Cuervo (440-600 MW), together with five plants (total capacity of approximately 2 750 MW) on the Baker and Pascua rivers in the southern region of Aysen.

China

Gross theoretical capability(TWh/yr)	5 920
Capacity in operation (MW)	231 000
Actual generation (GWh)	714 000
Capacity under construction (MW)	111 000

With its vast mountain ranges and numerous rivers, China's hydropower potential is the largest in the world. China is the world's largest producer of hydroelectric power and is aggressively building dams. Hydropower accounts for about 16 percent of China's electricity and 7 percent of its total energy consumption. It is planned to increase hydro-generating capacity by nearly two-thirds over the next five years.

While China is racing ahead to install more wind- and solar-power capacity, the energy generated by these technologies is considered too costly and insufficient to satisfy the country's huge power needs. The drought in 2011 reduced the output of hydroelectric power, contributing to a government decision to raise the cost of electricity for industrial use in 15 areas.

In 2010, China generated 714 TWh of electricity from hydroelectric sources. Installed hydroelectric generating capacity was 231 GW in 2011, according to FACTS Global Energy, accounting for over a fifth of total installed capacity. The China Electricity Council has plans to increase hydro capacity to 342 GW by 2015. The world's largest hydro power project, the Three Gorges Dam along the Yangtze River, was completed in July 2012 and includes 32 generators with a total capacity of 22.7 GW. The dam's annual average power generation is anticipated to be 84.7 TWh.

JBesides the Three Gorges project, there are many other massive plants in hand. Examples of such projects inclJJude Xiluodu (12 600 MW), Xiangjiaba (6 000 MW), Longtan (6 300 MW), Jinping II (4 800 MW), Xiaowan (4 200 MW), Laxiwa (4 200 MW), Jinping I (3 600 MW), Pubugou (3 600 MW), Dagangshan (3 600 MW) and Goupitan (3 000 MW).

Colombia

Gross theoretical capability (TWh/yr)	1 000
Capacity in operation (MW)	9 185
Actual generation (GWh)	45 583
Capacity under construction (MW)	3 833

Colombia's theoretical potential for hydropower is considerable, up to 1 000 TWh/yr, of which 20% is classed as technically feasible. Hydro output represents around 30% of the economically exploitable capability of 140 TWh/yr and accounted for about three-quarters of Colombia's electricity generation.

According to the Colombian Member Committee of WEC, there was 9 185 MW of hydropower in operation in 2011, generating a total of 45 583 GWh of electricity in that year.

Congo (Democratic Republic)

Gross theoretical capability (TWh/yr)	1 400
Capacity in operation (MW)	2 410
Actual generation (GWh)	U
Capacity under construction (MW)	0

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 exploitable capacity is put at 100 000 MW. The current level of hydroelectric output is equivalent to only around 3% of the republic's economically exploitable capability. Hydro provides virtually the whole of its electricity.

The national public electricity utility SNEL has 17 hydro plants, of which 11 plants have an installed capacity of over 10 MW. The total rated capacity of SNEL's hydropower plants is 2 410 MW; with the largest stations being Inga 1 (351 MW) and Inga 2 (1 424 MW). The power plants of these stations are either being (or planned to be) refurbished, in order to boost their faltering performance by an additional 660 MW. Moreover, a significant increase in capacity would be provided by the Inga 3 project (4 320 MW), which is currently in the planning phase.

There is also a huge scheme (Grand Inga, 40 000 MW or more), incorporating the supply of electricity to other parts of Africa via new long-distance high-voltage transmission lines. Both the power generating plant and transmission network have been the subject of preliminary investigations and pre-feasibility studies.

These studies identified three major African interconnection HVDC 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.

Costa Rica

Gross theoretical capability (TWh/yr)	223.5
Capacity in operation (MW)	1 510
Actual generation (GWh)	U
Capacity under construction (MW)	150

Costa Rica has a large hydroelectric potential. Its gross theoretical potential is estimated at 223.5 TWh/yr, within which a hydropower capacity of 5 694 MW has been assessed as economically feasible (after exclusion of areas within national parks).According to the Instituto Costarricense de Electricidad, aggregate installed hydro capacity was 1 510 MW at end-2008, equivalent to about 64% of Costa Rica's total generating capacity, and about 27% of its estimated economic potential.

Several new hydro plants are under construction or planned: nearing completion are Pirris (128 MW) and Toro 3 (50 MW), both due to enter service in 2011, together with three BOT schemes, each with 50 MW capacity and scheduled for operation in 2013: Torito on the Reventazon river, at the end of the tail-race of the Angostura HPP, and Capulin-San Pablo and Chucas on the Tarcoles. Two larger projects reported to be at the feasibility stage in 2009 were Diquís (622 MW), planned for completion in 2016, and Reventazón (298 MW), planned for 2014.

Czech Republic

Gross theoretical capability (TWh/yr)	13.1
Capacity in operation (MW)	1055
Actual generation (GWh)	2 134
Capacity under construction (MW)	0

The overall potential for all sizes of hydropower is quite modest (technically exploitable capability: 3 978 GWh/yr, as reported by the Czech WEC Member Committee). Total hydro-electricity output in 2011 was 2 134 GWh, representing 51% of this potential. Hydropower furnishes less than 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 2011 was 297 MW, equivalent to about 28% of the Czech Republic's total hydro capacity. Actual generation from small-scale schemes in 2011 was 1 159 GWh.

The *State Energy Concept* provides support for the construction of further small-scale HPPs, in particular through favourable feed-in tariffs, which guarantee a positive return on investment. Investment subsidies serve as another effective stimulus. The number of sites available for the construction of small hydro plants is reported to be small. Licensing procedures are fairly complex and often somewhat protracted.

The only planned extensions to the Czech Republic's hydro generating capacity comprise two small plants presently under construction; a 5 MW plant at Litomerice on the Elbe (Energo-Pro Co.) and a 0.5 MW plant at Melnik (CEZ, plc). Over half of the existing small HPPs use obsolete technology (dating from 1920-1950). There are plans to modernise the technology, with the aim of improving efficiency by up to 15%.

Ecuador

Gross theoretical capability (TWh/yr)	167
Capacity in operation (MW)	804
Actual generation (GWh)	U
Capacity under construction (MW)	U

The gross theoretical hydro potential is substantial, at about 167 TWh/yr, within which there is estimated to be an economically feasible capability of nearly 106 TWh/yr. Preliminary work at the site of the largest of the plants is under way, Coca Codo Sinclair (1 500 MW), have been completed; commercial operation is scheduled to commence in 2015.

Most of Ecuador's hydro capacity is located in Azuay province, in the south-central highlands. Paute-Molino is the country's single-largest hydroelectric complex, and alone claims almost 1.1 GW of capacity. Droughts in late 2009 affected flows in Paute River and caused the government to implement rolling blackouts from November 2009 to January 2010. To address capacity shortages, Ecuador plans to build six new hydroelectric power plants in the coming decade. Financing for all of the new projects have come from China.

Ethiopia

Gross theoretical capability (TWh/yr)	650
Capacity in operation (MW)	663
Actual generation (GWh)	U
Capacity under construction (MW)	2 150

There are enormous resources for hydro generation, the gross theoretical potential (650 TWh/yr) being second only to that of Congo (Democratic Republic) in Africa. The Ethiopian WEC Member Committee reports that only a small share of the assessed potential has been developed. Currently, hydropower provides more than 95% of Ethiopia's electricity.

Further capacity increases, at various stages of planning, total more than 7 500 MW. A contract was signed with China in July 2009 for constructing the Gibe IV and Halele Werabesa schemes, which will add 2 150 MW to Ethiopia's hydro capacity.

Finland

Gross theoretical capability (TWh/yr)	174
Capacity in operation (MW)	3 084
Actual generation (GWh)	12 278
Capacity under construction (MW)	U

Hydropower accounts for about 4% or Finland's total energy consumption. Hydropower's share of electricity production in Finland has varied in recent years within the range 10-15%, depending on precipitation levels and other hydrological conditions. Hydropower is Finland's second most widely exploited renewable energy source, after bioenergy. These plants have a total capacity of approximately 3,084 MW. Their total annual production has varied between 9.5 and 16.8 TWh, according to water conditions, in 2011 production totalled almost 12.3 TWh.

It could still be possible to increase Finland's hydropower capacity, though the main potential sources are generally well exploited. The total unexploited hydropower potential along river systems that are not protected for landscape or nature conservation is estimated at more than an annual production potential of 2 468 GWh. Of this potential 1 330 GWh/year is considered as economically exploitable. It is unlikely that hydropower developments could be launched along any remaining totally unharnessed rivers, for conservation reasons.

France

Gross theoretical capability (TWh/yr)	100
Capacity in operation (MW)	25 332
Actual generation (GWh)	50 300
Capacity under construction (MW)	U

France is one of Western Europe's major producers of hydroelectricity, but its technically feasible capacity has now been very largely exploited. The total hydroelectric generating capacity (excluding pumping) stands at
25 332 MW. The year's net production of 50.3 TWh compares with an estimated technically exploitable capability of 100 TWh/yr, of which 70% is considered to be economically exploitable.

The total output capacity of small-scale (less than 10 MW) plants is approximately 1 850 MW, which generated almost 7 TWh.

The PPI (long-term plan for investments in electricity generation) for the period 2009-2020 envisages targets for an increase of 3 TWh/yr in electricity output and of 3 000 MW in installed capacity through the installation of new small units and the enlargement of existing facilities.

Ghana

Gross theoretical capability (TWh/yr)	U
Capacity in operation (MW)	1 180
Actual generation (GWh)	5 600
Capacity under construction (MW)	400

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; their total net capacity, according to the Volta River Authority (VRA) website, is 1 180 MW. Electricity generation in Ghana is a responsibility of the VRA, which was established in 1961. The average annual output of its two existing hydro stations (circa 5 600 GWh) is equivalent to about half of Ghana's technically exploitable hydro capability.

Construction of the 400 MW Bui dam on the Black Volta is underway by China's Sino Hydro Corporation, and scheduled for completion in 2012.

Guinea

Gross theoretical capability (TWh/yr)	26
Capacity in operation (MW)	75
Actual generation (GWh)	U
Capacity under construction (MW)	80

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 reported that the gross theoretical hydro capability had been assessed as 26 TWh/yr, the technically exploitable capability as 19.3 TWh/yr and the economically exploitable capability as 19 TWh/yr.

The capacity potential corresponding to the technically exploitable capability of 19.3 TWh/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.

Additional hydro output which might feasibly become available in the longer term was 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 9.5 TWh/yr, equivalent to more than half the currently assessed economically exploitable capability.

Guinea intends to use its hydroelectric potentials to replace the supply of electricity by thermal power stations which is considerably more expensive. The country still faces some problems in this area. In the capital Malabo, power supply is assured 60% by one thermal power station and 40% by private generating sets. Unfortunately the supply of these private generating sets is small. To overcome these differences, the hydroelectric power station at Musala near Luba was built where its network covers an area of 1460km. In the same light, a hydroelectric power station with a capacity of 3.6 megavolts was built on the Rio Riaba. On the mainland, the thermal power station of Bata on Rio Muni has been equipped with two sets with a unit capacity of 700kw.

Iceland

Gross theoretical capability(TWh/yr)	184
Capacity in operation (MW)	1 900
Actual generation (GWh)	12 600
Capacity under construction (MW)	0

Hydropower is the main source of electricity production in Iceland. Today, hydroelectric plants account for approximately three-quarters of all electricity generated and consumed in Iceland. The remaining quarter comes from geothermal power stations. Hydro's gross theoretical potential of 184 TWh/yr including 40 TWh of economically exploitable output.

The largest hydroelectric stations utilize the flow of Iceland's glacial rivers, while numerous smaller hydropower plants are located in clear-water streams and rivers all around the country. All the major hydroelectric stations get their water from reservoirs, ensuring that these stations offer stable production year-round.

The 690 MW Fljótsdalur HPP, which is part of the Kárahnjúkar hydro scheme, came into operation in November 2007 and reached its full load in February of the following year. A further 80 MW of hydro capacity is under construction at the Búdarháls site on the Tungnaá river in southern Iceland. A number of other projects have been awarded licences or are at the planning stage.

The technically exploitable capability of small-scale hydro plants has been reported to be 12.3 TWh/yr, equivalent to about 19% of the level for total hydro. Installed capacity of small hydro at end-2008 was 55 MW, equivalent to 2.9% of total hydro capacity.

Iceland's precipitation has an enormous energy potential or up to 184 TWh/yr. Much of it is stored in ice caps and groundwater, and dissipated by evaporation, groundwater flow and glacier flow.

In total, all the hydropower stations in Iceland have a capacity of just under 1 900 MW and generate around 12 600 GWh annually. Due to new hydropower projects the capacity and generation will increase substantially in the next few years.

Iceland's largest hydropower station is Fjótsdalsstöð (Fljotsdalur Station) in Northeast Iceland, with a capacity of 690 MW. It generates close to 4,700 GWh annually. This is almost three times more than the power plant that comes in second place, which is Búrfellsstöð (Burfell Station) in the highlands of South Iceland. The powerful glacial rivers of South Iceland are the main source of Iceland's hydropower generation; numerous reservoirs and power stations in this area now generate more than 5,000 GWh annually.

India

Gross theoretical capability (TWh/yr)	2 638
Capacity in operation (MW)	38 106
Actual generation (GWh)	U
Capacity under construction (MW)	15 627

India's hydro resource is one of the largest in the world, its gross theoretical hydropower potential is estimated to be 2 638 TWh/yr, within which is a technically feasible potential of some 660 TWh/yr and an economically feasible potential of 442 TWh/yr. Out of the total power generation installed capacity in India of 1,760,990 MW (June, 2011), hydro power contributes about 21.6% i.e. 38,106 MW. A total capacity addition of 78,700 MW is envisaged from different conventional sources during 2007-2012 (the 11th Plan), which includes 15,627 MW from large hydro projects. In addition to this, a capacity addition of 1400 MW was envisaged from small hydro up to 25 MW station capacity. The total hydroelectric power potential in the country is assessed at about 150,000 MW, equivalent to 84,000 MW at 60% load factor. The potential of small hydro power projects is estimated at about 15,000 MW.

As part of India's 11th Five Year Plan, Teesta V (510 MW) in Sikkim and Omkareshwar (520 MW) in Madhya Pradesh have both recently been commissioned. Large hydro plants currently under construction within the 11th Five Year Plan include Subansiri Lower (2 000 MW) in Assam, and Parbati II (800 MW) and Parbati III (520 MW) in Himachal Pradesh.

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 in due course result in an increment of some 2 500 MW to India's generating capacity.

Indonesia

Gross theoretical capability (TWh/yr)	2 150
Capacity in operation (MW)	3 881
Actual generation (GWh)	12 419
Capacity under construction (MW)	0

At some 2 150 TWh/yr, Indonesia's gross theoretical hydro potential is the third largest in Asia. Its technically feasible potential is just over 400 TWh/yr, of which about 10% is considered to be economically exploitable. Average annual hydro output is about 12.5 TWh, indicating the evident scope for further development within the feasible potential. Hydro presently provides approximately 8% of Indonesia's electricity supply.

Iran (Islamic Rep)

Gross theoretical capability (TWh/yr)	179
Capacity in operation (MW)	8 746
Actual generation (GWh)	U
Capacity under construction (MW)	5 083

Hydropower & Dams World Atlas 2009 quotes the gross theoretical hydropower potential as 179 TWh/yr, of which 50 TWh/yr is regarded as technically feasible.

The Iranian WEC Member Committee reports that installed hydropower capacity was 8 746 MW at end-2011, and that Iran had 5 083 MW of hydro capacity under construction and that a further 10 426 MW was in various phases of planning.

Italy

Gross theoretical capability (TWh/yr)	200
Capacity in operation (MW)	18 092
Actual generation (GWh)	45 823
Capacity under construction (MW)	0

In Italy 67% of energy produced by renewable sources comes from hydroelectric. In Europe, Italy is one of the three major producers of hydroelectric energy, together with France and Spain. According to the Italian Member Committee of WEC current installed capacity is 18 092 MW. In 2011, total hydropower production amounted to 45 TWh of electricity. It has been calculated that the hydroelectric potential of the Italian territory could be approximately 200 TWh, of which 47 TWh is economically exploitable. When compared with the amount of energy produced, this indicates that the potential of the hydroelectric resources in Italy is exploited to about 95% and the maximum limit of possible exploitation has been reached. It therefore does not seem to be a sector that can expand further.

The fact that more favourable and convenient sites, from a technical and economical point of view, are already being utilized, contributes to the "closing" of this sector, and a number of technical, environmental and economic obstacles have arisen with regard to the realization of new high-capacity and high-output power stations. Consequently the future of hydroelectricity in Italy seems to consist in the realization of only the low-output (<100 kW) so-called micro-hydro plants, that imply a poor economic and technical commitment and have a very low impact on the environment.

The gross theoretical capability of small-scale HPPs in Italy is put at 38 000 GWh/yr (one-fifth of total hydro), within which the economically exploitable component is estimated to be 12 500 GWh/yr, as derived from the aforementioned *Italian Position Paper*.

Plants with a capacity of less than 10 MW represented approximately 14% of total installed hydro capacity, with facilities in the 1-10 MW class accounting for about 11% and the smaller plants for around 3%. As there are problems in building large HPPs, future increases in hydro output may be provided very largely by small hydropower projects.

Japan

Gross theoretical capability (TWh/yr)	U
Capacity in operation (MW)	22 362
Actual generation (GWh)	72 639
Capacity under construction (MW)	291

A high proportion of Japan's massive potential for hydro generation has already been harnessed. Most of the sites suitable for the installation of large-scale conventional hydro-electric plants have now been developed. The great majority of the larger hydro projects presently under construction or planned in Japan are pumped-storage schemes. In 2011 Japan had about 291 MW of all types of hydro capacity 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-2011 was about 3.5 GW, equivalent to 12.5% of total conventional hydro capacity. Small-scale capacity planned for construction totalled 30 MW, with a probable annual generation of 304 GWh.

Jordan

Gross theoretical capability (TWh/yr)	U
Capacity in operation (MW)	0
Actual generation (GWh)	0
Capacity under construction (MW)	10

The Jordanian WEC Member Committee reported that pre-feasibility studies had indicated a technical hydro potential of 400-800 MW through 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. In July 2008, the World Bank awarded a contract for a feasibility study, which was expected to take 24 months to complete.

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.

Kazakhstan

Gross theoretical capability(TWh/yr)	170 000
Capacity in operation (MW)	2 267
Actual generation (GWh)	7 849
Capacity under construction (MW)	300

The WEC Member Committee reports that the main hydropower resources are located in the eastern and southeastern regions of the country:

- on the Irtysh river – Bukhtarma (675 MW), Ust-Kamenogorsk (332 MW) and Shulbinsk (702 MW);
- on the Ili river – Kapchagay (364 MW);
- on the Syrdarya river – Shardara (100 MW).

The Moinak HPP (300 MW) is presently under construction. By 2020 it is planned to commission Kerbulak (50 MW), Bulak (68 MW) and number of smaller HPPs with a total installed capacity of 56 MW.

In Kazakhstan, according to existing legislation, small-scale HPPs include those with a capacity of up to 35 MW.

Laos

Gross theoretical capability (TWh/yr)	U
Capacity in operation (MW)	700
Actual generation (GWh)	U
Capacity under construction (MW)	5 361

Only a very small proportion of Laos's massive hydro endowment has so far been harnessed. Its technically feasible potential is quoted by ***Hydropower & Dams World Atlas 2009*** (HDWA) as 18 000 MW, whereas its total installed hydropower capacity at end-2008 was less than 700 MW.

According to HDWA, the Ministry of Energy and Mines lists 60 HPPs, with a total installed capacity of 16 061 MW, as being at various stages of construction or planning. Six hydro schemes, with a total capacity of 2 131 MW, were under construction in 2009, with twelve more totalling 3 230 MW reported to be at an advanced stage of negotiation. An additional 42 projects, totalling 10 700 MW, are the subject of feasibility studies.

Much of the new hydro generating capacity is destined to meet demand from neighbouring countries; export arrangements are already in place with Thailand, Vietnam and Cambodia. Among the plants presently under construction, the largest are:-

- Nam Ngum 2 (615 MW), scheduled for completion in 2013;
- Nam Theun 1 (424 MW), due to enter operation in 2014 (exporting to Thailand);
- Xe Kaman 3 (250 MW, completion expected in 2010 (90% of its output to be sold to Vietnam).

In March 2010, the Nam Theun 2 HPP (1 070 MW) began commercial exports of electricity to the Thai state utility EGAT.

Lithuania

Gross theoretical capability (TWh/yr)	2
Capacity in operation (MW)	U
Actual generation (GWh)	U
Capacity under construction (MW)	U

The Lithuanian WEC Member Committee states that, based on the provisions of the National Energy Strategy, the possibility of constructing HPPs (with capacities of more than 10 MW) on the River Neris could be considered. However, their construction is uncertain, in view of environmental restrictions.

The Kruonis pumped storage plant was built in 1992-1998 and comprises four units, each with a capacity of 225 MW. The plant serves to supply the peak and semi-peak loads of Lithuanian consumers and neighbouring countries.

Opportunities for the construction of small HPPs with capacity of less than 10 MW are limited. The total probable annual generation of existing and new small hydro plants is expected by the Member Committee to reach about 160 GWh in 2020.

Up to now, hydropower has been the main renewable energy source for power production. Due to the topographical conditions, the potential for hydropower is rather low. The economically feasible potential for hydro resources is estimated at 2.2 TWh/ year . Approximately 14% of this resource is currently being exploited. Legislation protecting many of Lithuania's rivers from development for ecological and cultural reasons hampers further exploitation of hydropower . 130 possible locations have been identified for the renovation or construction of small hydropower plants, with a potential production of up to 60 million kWh/year.

Macedonia (Republic)

Gross theoretical capability (TWh/yr)	U
Capacity in operation (MW)	U
Actual generation (GWh)	U
Capacity under construction (MW)	U

Out of a number of hydro plants being planned as BOT schemes in 2009, the largest were Galishte (194 MW) on the river Vardar, and a 333 MW pumped-storage plant at Chebren on the Black river.

Madagascar

Gross theoretical capability (TWh/yr)	321
Capacity in operation (MW)	124
Actual generation (GWh)	700
Capacity under construction (MW)	29

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, of which about 27% is deemed to be economic. With current installed capacity standing at 124 MW and annual hydro output about 700 GWh, the island's hydro capability has scarcely begun to be utilised.

There are three HPPs of over 10 MW installed capacity in service: Mandraka (24 MW), Andekaleka (58 MW) and Sahanivotry (15 MW). An additional 29 MW unit is being installed at Andekaleka, while Mandraka II (57 MW) will be developed to utilise the full head available at the site.

With the abundance of small rivers on the island, hydropower has become the environmentally sound choice for generating electricity, and Madagascar's seven hydro-electric power stations contribute two-thirds of the country's electric power.

The 15-MW Sahanivotry Hydro-Electric Power Station was commissioned in 2008 on the Sahanivotry River south of Antsirabe in the province of Antananarivo. It is Madagascar's first privately owned and operated hydro plant and the first to be built on the island since 1982. Currently producing 10 percent of the island's electricity supply, Sahanivotry feeds the Antananarivo and Antsirabe grid, which have experienced chronic power outages.

Malaysia

Gross theoretical capability (TWh/yr)	123
Capacity in operation (MW)	0
Actual generation (GWh)	0
Capacity under construction (MW)	3 344

There is a substantial potential for hydro development in Malaysia, 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.

Construction of the 2 400 MW Bakun hydro plant in Sarawak is being completed. Work on the 944 MW Murum hydro project (also in Sarawak) is progressing, with the plant due to commence operations in 2013.

Mexico

Gross theoretical capability (TWh/yr)	42 000
Capacity in operation (MW)	11 499
Actual generation (GWh)	35 796
Capacity under construction (MW)	750

Historically, Mexico has derived much of its power from hydroelectric facilities. Many small, technologically-dated hydroelectric power plants are still operating in remote areas of the country, some of which date back to the 1920s. Hydroelectric plants presently account for more than 11,499 megawatts (MWe) of electric generation capacity, or about one-fourth of the total generation capacity in Mexico.

Mexico has not exhibited a policy promoting large-scale expansion of hydroelectric power like many of its Latin American neighbours. Because of the relative arid conditions over much of the northern part of the country, there are relatively few sites suitable for new hydroelectric development. Current estimates for Mexico's total hydroelectric potential are about 42,000 MWe. However, environmental concerns and the need to relocate rural communities stand in the way of greater utilization of the country's water resources for hydroelectric energy.

Projects to harness the Usumacinta River and other waterways have been cancelled due to opposition from local groups. One such project was the El Caracol power plant on the Balsas River, where a doubling of the facility's 609 MWe capacity had been planned.

However, severe droughts in parts of Mexico in the past few years have significantly curtailed hydroelectric power generation. The drought of summer 2000 took 900 MWe of hydroelectric capacity in northeast Mexico offline and forced the CFE to depend on hydroelectric facilities in the southeast where water levels allowed normal hydroelectric operations. As of June 2002, dry conditions in Sinaloa and Sonora states

For the present *Survey*, the Mexican WEC Member Committee has reported that La Yesca (750 MW) is under construction for CFE, and that 1 374 MW of hydro capacity is planned by CFE for future development. Generating capacity at La Villita Michoacán is being boosted by 400 MW, and at Infiernillo Guerrero by 200 MW, through refurbishment and uprating programmes. The start of construction work on CFE's La Parota (900 MW) hydro project on the Papagayo river has been put back by three years, with completion now scheduled for 2021.

Installed capacity of small-scale hydropower is reported by the Mexican WEC Member Committee to have been 125 MW.

Mozambique

Gross theoretical capability (TWh/yr)	U
Capacity in operation (MW)	107
Actual generation (GWh)	U
Capacity under construction (MW)	1 500

The main electricity authority in the country is Electricidade de Mozambique (EDM), established by the state in 1977, two years after independence. EDM is responsible for generation, transmission and distribution, but there are other companies that produce and distribute electricity. The main one is Hidroelectrica de Cahora Bassa, a company jointly owned by Portugal (82%) and Mozambique (18%) and the biggest hydroelectric scheme in Southern Africa.

Operations at Cahora Bassa, on the south side of the Zambezi River, are operating at higher capacities following restoration of the DC transmission line from Cahora Bassa to South Africa by EDM and Eskom, the South African power utility. Other large hydro power plants in Mozambique have continued to operate at less than full capacity, including Mavuzi (44.5 MW effective capacity out of 52 MW nominal capacity); Chicamba (34 MW of 38.4 MW); and Corumana (14 of 16.6 MW).

Mozambique is seeking to boost power output as demand grows in South Africa. The country also needs to meet a national growing demand from a planned titanium plant and a possible future expansion to an aluminium plant.

Mozambique is one of the largest power producers in the SADC region. It is also a member of the Southern African Power Pool (SAPP).

By mid-2009, a framework agreement had been signed for the 1 500 MW Mphanda Nkuwa hydro scheme, and environmental studies had been completed. Other potential future hydro projects in Mozambique include Boroma (444 MW) and Lupata (654 MW).

Myanmar (Burma)

Gross theoretical capability (TWh/yr)	140
Capacity in operation (MW)	1 541
Actual generation (GWh)	3 900
Capacity under construction (MW)	1 500

The country is well endowed with hydro resources: its technically feasible potential is given by *Hydropower & Dams World Atlas* as 39 720 MW. At an assumed annual capacity factor of 0.40, this level would imply an annual output capability of almost 140 TWh; actual output in 2011 was only 3.9 TWh. There thus appears to be ample scope for substantial development of hydropower in the long term.

The Shweli 1 plant (600 MW) on the Shweli river in northeast Myanmar was completed in 2008. Work on the Yeywa (790 MW) project on the Myitnge river, towards the centre of the country, is nearing completion. Longer-term projects include a major export-orientated scheme, Ta Sang (7 110 MW) on the Thanlwin (or Salween) river, from which it is planned to supply 1 500 MW to Thailand.

In March 2010, construction of this project (the first of a planned series of five HPPs on this river) was reported to be getting under way. More than 5 000 MW of additional hydro capacity is planned, involving 14 projects, including Shweli 2 (640 MW), Shweli 3 (360 MW), Shwezaye (660 MW) and Tanintharyi (600 MW).

Namibia

Gross theoretical capability (TWh/yr)	U
Capacity in operation (MW)	0
Actual generation (GWh)	0
Capacity under construction (MW)	0

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. 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.

Nepal

Gross theoretical capability (TWh/yr)	U
Capacity in operation (MW)	600
Actual generation (GWh)	U
Capacity under construction (MW)	U

Nepal has a huge hydropower potential. In fact, the perennial nature of Nepali rivers and the steep gradient of the country's topography provide ideal conditions for the development of some of the world's largest hydroelectric projects in Nepal. Current estimates are that Nepal has approximately 40,000 MW of economically feasible hydropower potential. However, the present situation is that Nepal has developed only approximately 600 MW of hydropower.

Therefore, bulk of the economically feasible generation has not been realized yet. Besides, the multipurpose, secondary and tertiary benefits have not been realized from the development of its rivers.

The hydropower system in Nepal is dominated by run-of-river Projects. There is only one seasonal storage project in the system. There is shortage of power during winter and spill during wet season. The load factor is quite low as the majority of the consumption is dominated by household use. This imbalance has clearly shown the need for storage projects, and hence, cooperation between the two neighbouring countries is essential for the best use of the hydro resource for mutual benefit.

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.

Norway

Gross theoretical capability (TWh/yr)	22
Capacity in operation (MW)	1 521
Actual generation (GWh)	6 800
Capacity under construction (MW)	1 021

Norway possesses Western Europe's largest hydro resources, both in terms of current installed capacity and of economically feasible potential. Hydro generation provides virtually all of Norway's electric power.

According to HDWA, more than fifty (mostly quite small) hydro plants were under construction in Norway. The economically exploitable capability applicable to small-scale hydro schemes was reported by HDWA to be 22.1 TWh/yr. Installed capacity of small hydro plants was stated to be 1 521 MW, with an average annual output capability of 6.8 TWh. Some 326 were planned, with an installed capacity totalling 1 021 MW and annual output averaging 3 663 GWh.

Pakistan

Gross theoretical capability (TWh/yr)	475
Capacity in operation (MW)	6 481
Actual generation (GWh)	27 700
Capacity under construction (MW)	1 600

The total Hydropower resource in Pakistan is estimated at about 50,000 MW. Most of the resources are located in the North of the country, which offers sites for large scale (100 MW to 7,000 MW) power projects. Smaller (less than 50 MW) sites are available throughout the country. In addition, canal system with total of 58,450 km watercourses, farm channels and field ditchers running another 160,000 km in length has a huge hydropower potential at numerous sites/locations on each site, ranging from 1 MW to more than 10 MW hydro plants can be installed.

The total installed hydro capacity was 6 481 MW, almost exactly one-third of total national generating capacity. According to ***Hydropower & Dams World Atlas***, Pakistan has a gross theoretical hydro potential of approximately 475 TWh/yr, of which some 204 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.

Hydro capacity in operation included major plants at Tarbela (3 478 MW), Ghazi Barotha (1 450 MW) and Mangla (1 000 MW); gross hydro-electric output during the year was 27.7 TWh, accounting for 30% of Pakistan's electricity generation.

In 2009 the 969 MW Neelum Jhelum hydro scheme and various smaller schemes in the 70-130 MW bracket were reported to be moving ahead. Several huge public sector projects – including Bunji (7 100 MW), Diamer Basha (4 500 MW) and Dasu (4 320 MW), all sited on the Indus – are being developed, as well as private-sector schemes such as Kohala (1 100 MW) on the Jhelum. Total hydro capacity reported to be under construction in early 2009 was some 1 600 MW. About 17 000 MW of additional hydro capacity is planned for construction starts over the next ten years.

HDWA quotes Pakistan's small-scale (1-22 MW) hydro potential as 302 GWh/yr, but states that only 68 MW out of an installed capacity of 107 MW is actually in operation. A total of 350 MW of small hydro capacity is reported to be planned.

Paraguay

Gross theoretical capability (TWh/yr)	111
Capacity in operation (MW)	8 130
Actual generation (GWh)	0
Capacity under construction (MW)	U

Paraguay has replaced all thermal power by hydro power in 1970s. Now the country completely relies on 2 hydroelectric plants for electricity.

The hydroelectric plants are Yacryetá and Itaipú. The Itaipu dam is situated in the eastern side of Paraguay, near the city of Ciudad del Este. The dam is built on the River Parana which is on the border between the two nations, Brazil and Paraguay. The original intention behind this project was to supply water to people, especially during the phase of drought. It is also the world's second largest hydroelectric plant.

The project began producing electricity in 1984. It has about 3,200 employees and has sales revenue of about 3.369 million dollars. The total power produced is 14,000 MW from 20 generators. The construction took 16 years. This dam is 5 miles in length and 643 feet heighted. A large amount of steel and iron have been used in the project.

The country's gross theoretical capability for hydroelectricity is about 111 TWh/yr, of which 68 TWh is estimated to be economically exploitable.

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 operating at only 120 MW per unit, owing to the level of the reservoir being held below that originally planned. The level of the Yacyréta reservoir is being raised, which will enable the bi-national plant's turbines to operate nearer to their design capacity of 155 MW each.

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 the existing Yguazu dam. 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. The 300 MW Aña-Cuá scheme constitutes another bi-national project with Argentina.

Peru

Gross theoretical capability (TWh/yr)	260
Capacity in operation (MW)	3 242
Actual generation (GWh)	U
Capacity under construction (MW)	U

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 one of the largest in the whole of South America, with an economically exploitable capability of some 260 TWh/yr. Current utilisation of this capability is very low - at around 7%. Hydro provides nearly 60% of Peru's electric power.

There is deemed to be scope for additional hydro capacity capable of producing about 2 552 GWh/yr. If all this capacity were to be developed, the presently estimated economically exploitable capability would be exceeded, but installed capacity would still be well within the assessed technical limit.

Small-scale hydro accounts for 274 MW of installed capacity, which produce an estimated 491 GWh. Planned capacity increases in the less-than-10 MW category amount to some 111 MW, of which 61 MW relates to units of between 4 and 10 MW and 50 MW to smaller units. Altogether these new units would produce an estimated 426 GWh/yr.

Romania

Gross theoretical capability (TWh/yr)	36
Capacity in operation (MW)	6 144
Actual generation (GWh)	14 954
Capacity under construction (MW)	0

Romania has an estimated total usable hydro power of approximately 36 TWh per year and a significant part of this potential is already used for electricity generation.

Hydro power is one of the main contributors to the total electricity generation in Romania, with a contribution of around 30% of the total power delivered to the grid. In 2010 hydro power plants had a total installed capacity of over 6400 MW and produced 19.8 TWh electricity.

The vast majority of this production results from large-scale reservoir hydro power plants.

Run-of-the-river Small Hydro Power Plants (SHP) were built for a long period of time, but only recently, after the emergence of the Renewable Energy Act 220/2008, the interest in building and operating such power generators was revamped

Russian Federation

Gross theoretical capability(TWh/yr)	2 295
Capacity in operation (MW)	49 700
Actual generation (GWh)	180 000
Capacity under construction (MW)	3 000

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 2011 (approximately 180 TWh) represented 21% of the economic potential and accounted for about 19% of total electricity generation.

The largest hydro scheme currently under construction in the Russian Federation is the 3 000 MW plant at Bogucchany on the Angara river in southeast Siberia..

Major hydro developments are under consideration for the Volga-Kama cascade (expanding capacity by 2 010 MW), and for up to seven HPPs on the Timpton river in South Yakutia (with a total installed capacity of 9 000 MW). The first plant to be built under the latter scheme would be Kankunskaya (1 600 MW).

South Africa

Gross theoretical capability (TWh/yr)	U
Capacity in operation (MW)	661
Actual generation (GWh)	U
Capacity under construction (MW)	U

The current emphasis in South Africa is very much on the development of pumped-storage facilities. Two large plants - Ingula (1 332 MW) and Lima (1 500 MW) are under construction, and further projects are being studied.

The US department of energy estimates that there are 6 000 to 8 000 potential sites in South Africa suitable for small hydro-utilisation below 100 megawatts, with the provinces of KwaZu-lu-Natal and the Eastern Cape offering the best prospects.

The largest hydroelectric power plant in South Africa is the 1 000 megawatt Drakensberg Pumped-Storage Facility, part of a larger scheme of water management that brings water from the Tugela River into the Vaal watershed.

The country's second-largest plant is situated on the Palmiet River outside Cape Town.

Spain

Gross theoretical capability (TWh/yr)	162
Capacity in operation (MW)	18 540
Actual generation (GWh)	25 000
Capacity under construction (MW)	450

In terms of hydro-electric resources, Spain stands in the middle rank of West European countries, with a gross theoretical capability of 162 TWh/yr. The average level of hydro-electricity generation (excluding pumped-storage plants) in 2011 (approximately 25 TWh) indicates that Spain has already harnessed a considerable proportion of its economic hydro resources.

Currently some 450 MW of small hydro capacity is scheduled to be added, leading to an eventual total output from small-scale hydro of around 6 000 GWh/yr.

Sudan

Gross theoretical capability (TWh/yr)	19
Capacity in operation (MW)	1 825
Actual generation (GWh)	U
Capacity under construction (MW)	U

The economically feasible potential is some 19 TWh/yr. Until recently, hydro development had been on a very limited scale, with end-2008 installed capacity only about 575 MW. However, following the completion of the 1 250 MW Merowe HPP in early 2010, the country's hydro capacity has risen to over three times its 2008 level.

In 2008, a contract was awarded for the design of five hydro schemes in northern Sudan. Most of Sudan's pre-2008 hydro plant is at least 40 years old, providing a potential for uprating estimated at about 200 MW.

Swaziland

Gross theoretical capability (TWh/yr)	U
Capacity in operation (MW)	60
Actual generation (GWh)	69
Capacity under construction (MW)	0

According to the Swaziland Electricity Company, there is 60.4 MW of hydropower capacity in operation in 2011. These plants produce approximately 15% of the country's total electricity demand, the remainder being imported from neighbouring countries.

Sweden

Gross theoretical capability (TWh/yr)	66
Capacity in operation (MW)	16 197
Actual generation (GWh)	66 000
Capacity under construction (MW)	0

Today the total number of hydropower plants in Sweden is 2 057 of which 1 615 have an installed capacity of maximum 10 MW. The total capacity is 16 197 MW of which 1 050 MW is small hydro (plants less than 10 MW).

The total electricity production is 66 TWh during a normal year 4.6 TWh of which is produced in SHP. According to the BlueAGE study issued by ESHA in 2001, Sweden has a fifth position in energy winning in small hydropower in Europe having Italy, France, Germany and Spain ahead.

The construction of new hydro plants has largely ceased, on account of environmental and political considerations. Future activity is likely to be very largely confined to the modernisation and refurbishment of existing capacity.

As in many European countries large hydro is considered almost fully developed, but there is still a potential for developing small hydro in Sweden. The BlueAGE study shows a Swedish potential of almost 2 TWh in upgrading existing plants and constructing new plants taking into account technical, economical and environmental constraints.

The Swedish manufacturing industry has been very successful with the first commercial turbines manufactured in 1845 and with well known manufacturers as KMW, NOHAB, Finshyttan and ASEA with products spread all over the world.

Switzerland

Gross theoretical capability (TWh/yr)	U
Capacity in operation (MW)	13 723
Actual generation (GWh)	32 069
Capacity under construction (MW)	1995

Today there are 556 hydropower plants in Switzerland that each have a capacity of at least 300 kilowatts, and these produce an average of around 35,830 GWh per annum, 47% of which is produced in run-of-river power plants, 49% in storage power plants and approximately 4% in pumped storage power plants.

Two-thirds of hydroelectricity are generated in the mountain cantons of Uri, Grisons, Ticino and Valais, while Aargau and Bern also generate significant quantities. Roughly 11% of Switzerland's hydropower generation comes from facilities situated on bodies of water along the country's borders.

Whilst Switzerland has already developed a relatively high proportion (over 85%) of its substantial economically exploitable hydro capability, attention is now being focused on small-scale hydropower (defined in Switzerland as schemes below 300 kW). Under the new feed-in regime introduced in 2008, mini-hydro projects totalling 354 MW, with an estimated output of 1 464 GWh, have qualified for feed-in tariffs and are thought likely by the Swiss WEC Member Committee to be built in the coming years.

Tajikistan

Gross theoretical capability (TWh/yr)	263.5
Capacity in operation (MW)	5 500
Actual generation (GWh)	11 200
Capacity under construction (MW)	0

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 about 95% of Tajikistan's electricity generation.

Installed hydro capacity amounts to about 5 500 MW, of which just over 5 000 MW was reported to be operational in early 2009. The principal site is Nurek (3 000 MW), which produces approximately 11.2 TWh/yr. The fourth and last unit at the Sangtuda 1 plant on the river Vakhsh came into operation in May 2009; together, the four units have added 670 MW to Tajikistan's capacity.

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..

Tanzania

Gross theoretical capability (TWh/yr)	U
Capacity in operation (MW)	561
Actual generation (GWh)	U
Capacity under construction (MW)	U

The 900 MW Stieglers Gorge hydro project on the river Rufiji appears to be moving ahead, with the Canadian-registered company Energem Resources acquiring a 40% stake in the scheme.

Tanzania's interconnected grid system has an installed capacity of 773MW, of which 71% is hydropower. The largest hydropower complexes are the Mtera and Kidatu Dams and they are situated on the Great Ruaha River. The Mtera Dam is the most important reservoir in the power system providing over-year storage capability. It also regulates the outflows to maintain the water level for the downstream Kidatu hydropower plant

The installed capacity of the hydropower facilities are: - the Kidatu power station, which has the capacity of 204 MW; - the Kihansi power station, which has the capacity of 180 MW; - the Mtera power station, which has the capacity 80 MW; - the Pangani power station, which has the capacity of 68 MW; - the Hale power station, which has the 21 MW; and - Nyumba ya Mungu, which has the capacity of 8 MW The total capacity of hydropower generation is 561 MW.

Turkey

Gross theoretical capability (TWh/yr)	432
Capacity in operation (MW)	17 259
Actual generation (GWh)	57 472
Capacity under construction (MW)	8 270

There is about 432 TWh per year in hydropower potential in Turkey. About 35 per cent of hydropower potential is used to generate electricity and hydropower plants with an installed capacity of 17 MW in operation, generating 57 GWh in 2011. Many private companies are developing small and medium size hydropower projects.

A further 8.2 GW of capacity was under construction, with an envisaged total average output of around 25 TWh/yr. Some 23 TWh of additional capacity is planned for development over the longer term.

According to HDWA, Turkey's small-scale hydropower potential is an estimated 39 000 GWh/yr. The total installed capacity of such HPPs is quoted as 636 MW, providing an average output of 2 545 GWh/yr.

Uganda

Gross theoretical capability (TWh/yr)	U
Capacity in operation (MW)	U
Actual generation (GWh)	U
Capacity under construction (MW)	U

Following a successful financial closure at the end of 2008, contracts have been awarded for the 250 MW Bujagali scheme, and work is now well under way. The project is for five 50 MW units, to be installed at a site on the Victoria Nile, approximately 8 km downstream of the 180 MW Nalubaale (formerly Owen Falls) station, and is scheduled for commissioning in 2011-2012.

United Kingdom

Gross theoretical capability (TWh/yr)	4
Capacity in operation (MW)	1 630
Actual generation (GWh)	5 700
Capacity under construction (MW)	0

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*** quotes the technically feasible potential for small hydro so defined as 4 100 GWh/yr, with the economically feasible potential for undeveloped sites as 1 000 GWh/yr.

The UK WEC Member Committee reports that a study into the potential hydro resource is currently under way. The draft findings of this study show a potential of up to 248 MW of small-scale hydro left to be developed in England and Wales. This study complements one undertaken in Scotland on behalf of the Forum for Renewable Energy Development in Scotland, which showed a potential for up to 657 MW of small-scale hydropower.

The 2008 Energy Act provided the wherewithal for the Government to introduce feed-in tariffs (FIT). From 1 April 2010 renewable energy electricity-generating technologies, up to a maximum of 5 MW, qualify for generation and export tariffs. FITs will work alongside the Renewables Obligations. In the case of new hydro schemes, where both the product and installer are certificated, the generation tariffs are on a decreasing scale from GBP 0.199/kWh for up to 15 kW capacity to GBP 0.045/kWh for installations of 2-5 MW. These rates will remain the same for a period of 20 years (although adjusted for inflation through a link to the Retail Price Index). The tariff payable for electricity exported to the grid is GBP 0.03/kWh, regardless of the size of the installation.

The UK currently (2011) generates about 1.5% (5,700 Gwh) of its electricity from hydroelectric schemes - most of which are large-scale schemes in the Scottish Highlands.

Hydroelectric energy uses proven and efficient technology; the most modern plants have energy conversion efficiencies of 90% and above. Hydro has a typical load factor of 35 to 40%.

United States of America

Gross theoretical capability(TWh/yr)	2 040
Capacity in operation (MW)	77 500
Actual generation (GWh)	268 000
Capacity under construction (MW)	0

The hydro resource base is huge: the United States WEC Member Committee reports that the gross theoretical potential was assessed in 2006 as 2 040 TWh/yr, and that the annual technically exploitable capability is 1 339 TWh, based on publications of the U.S. Department of Energy (Idaho National Environmental and Engineering Laboratory), other U.S. Departments and the Electric Power Research Institute (EPRI). The end-2011 hydro capacity of 77.5 GW had an average annual capability of about 268 TWh, equivalent to 20% of the assessed technical potential.

The Member Committee states that there have been no comprehensive assessments of the U.S. potential for all economically exploitable hydropower, and that, moreover, the economics of these projects is unknown and is in constant flux due to policy and commodity pricing.

On the issue of Exploitable Capability, the U.S. Member Committee quotes from the 2006 report by the Idaho National Laboratory:

'It is concluded from the study results that there are a large number of opportunities for increasing U.S. hydroelectric generation throughout the country that are feasible based on an elementary set of feasibility criteria. These opportunities collectively represent a potential for approximately doubling U.S. hydroelectric generation (not including pumped storage), but more realistically offer the means to at least increase hydroelectric generation by more than 50%.

The reported technically exploitable capability of small-scale hydropower (5 MW and below) is 782 TWh, with about 198 TWh/yr rated as economically exploitable. The installed generating capacity of small hydro plants totalled 2.86 GW at end-2008; probable annual generation is put at 10 154 GWh, but actual generation in 2008 was some 18% higher, at 11 973 GWh, equivalent to 4.8% of total U.S. hydro output.

Various incentives for small-scale hydro exist in the form of Federal and State production tax credits and Federal grants and loan guarantees. Moreover the Federal Energy Regulatory Commission, which is responsible for the licensing of private, municipal and State hydro-electric projects, has an exemption for hydro projects with an installed capacity of 5 MW or less which also meet certain conditions.

In the United States, hydropower has grown steadily, from 56 GW in 1970 to more than 95 GW today.[4] As a percentage of the U.S. electricity supply mix, however, it has fallen to 10 percent, down from 14 percent 20 years ago, largely as a result of the rapid growth in natural gas power plants. In terms of electricity production, hydropower plants account for about seven percent of America's current power needs.[5]

In some parts of the country, hydropower is even more important. For example, the Pacific Northwest generates more than two-thirds of its electricity from 55 hydroelectric dams.[6] The Grand Coulee dam on the Columbia River is one of the largest dams in the world, with a capacity of nearly 6,500 megawatts (MW).

In addition to very large plants in the West, the United States has many smaller hydro plants. In 1940 there were 3,100 hydropower plants across the country, but by 1980 that number had fallen to 1,425. Since then, a number of these small plants have been restored; there are currently 2,378 hydro plants (not including pumped storage) in operation.[7]

These plants account for only a tiny fraction of the 80,000 dams that block and divert our rivers. As a result, there is a significant opportunity for growth according to the National Hydropower Association, which estimates that more than 4,300 MW of additional hydropower capacity can be brought online by upgrading existing facilities.[8]

Uruguay

Gross theoretical capability (TWh/yr)	32
Capacity in operation (MW)	1 538
Actual generation (GWh)	6 479
Capacity under construction (MW)	0

Between 2003 and 2007, 68% of Uruguay's energy needs were met by hydroelectric dams on the Uruguay River. The largest of these impoundments, the Salto Grande, a facility shared with Argentina, has generated up to half of Uruguay's electricity in the past. Apart from the bi-national Salto Grande, with a total capacity of 1,890 MW, existing plants are Terra (152 MW), Baygorria (108 MW), Constitucion (333 MW). All the potential for large hydro in Uruguay has already been developed.

According to the Uruguayan Member Committee of WEC the technically exploitable potential is 10 TWh/yr, within a gross theoretical potential of 32 TWh. Some 6 TWh/yr of hydro capacity is regarded as economically feasible for development at present. At the end of 2011 operational capacity was 1 538 MW with a total production of 6 479 GWh of electricity that year. No new capacity was under construction at the time.

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 and only about 70 MW is planned: future increases in generating capacity are likely to be largely fuelled by natural gas.

Venezuela

Gross theoretical capability (TWh/yr)	731
Capacity in operation (MW)	14 627
Actual generation (GWh)	86 700
Capacity under construction (MW)	0

Hydroelectricity provides the bulk of Venezuela's electricity supply. Most of the country's hydro production facilities are located on the Caroni River in the Guayana region. The 8,900-megawatt Guri Hydroelectric Power Plant on the Caroni is one of the largest hydroelectric dams in the world and provides the majority of Venezuela's electric power.

Water levels at the Guri Dam dropped to record-low levels during the 2009-2010 drought, forcing the country to implement rolling blackouts, reduce industrial production, and fine large users for excessive consumption. Venezuela plans to expand hydroelectric production in the future.

Hydropower & Dams World Atlas (HDWA) reports a gross theoretical hydropower potential of 731 TWh/yr, of which 261 TWh/yr is considered as technically feasible and approximately 100 TWh/yr economically exploitable. Hydro-electric output in 2008 was 86.7 TWh. About 73% of the republic's electricity requirements are met from hydropower.

In early 2009, hydro capacity in operation amounted to 14 627 MW. The principal HPPs under construction were Tocoma (2 160 MW) on the river Caroní and La Vueltosa (514 MW) in the Andean region.

A large increase in hydro-electric capacity occurred during the 1980s, the major new plant being Guri (Raúl Leoni), on the Caroní in eastern Venezuela - its installed capacity of 8 850 MW makes it one of the world's largest hydro stations. The Tocoma HPP, located 18 km downstream of Guri, is the last in the series of major hydro plants constructed by the state-owned company EDELCA on the lower Caroní. Eventually, the total installed capacity on the lower Caroní (comprising, in order of flow, Guri, Tocoma, Caruachi and Macagua) will exceed 16 000 MW.

HDWA states that no very large hydro plants are firmly planned for the next ten years, but mentions a number of schemes that have been studied, including several on the upper and middle reaches of the Caroní and others on the Colorada in the Andean region.

Vietnam

Gross theoretical capability (TWh/yr)	300
Capacity in operation (MW)	5 500
Actual generation (GWh)	24 000
Capacity under construction (MW)	0

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 100 000 GWh/yr. Total installed hydro capacity was about 5 500 MW at end-2008 and an output of about 24 TWh provided about one-third of Vietnam's power supply. The largest HPPs currently in operation are Hoa Binh (1 920 MW), Yali (720 MW), Tri An (420 MW) and Ham Thuan (300 MW).under BOT or IPP arrangements.

Zambia

Gross theoretical capability (TWh/yr)	U
Capacity in operation (MW)	1 730
Actual generation (GWh)	U
Capacity under construction (MW)	U

Zambia's two major hydro plants are being refurbished and upgraded: the 900 MW Kafue Gorge (Upper) station by 90 MW and Kariba North Bank (presently 600 MW) by 120 MW. Economic and technical feasibility studies are being conducted on the Kafue Gorge Lower

IPP project (750 MW) and a 210 MW scheme at Kalungwishi. Further rehabilitation and new-build projects are being developed or studied, including the 120 MW Itezhi Tezhi scheme on the Kafue river and the 1 800 MW Baroka Gorge bi-national project with Zimbabwe.

The national installed capacity presently stands at 1,730 Mega Watts (MW) but the demand is more than 2, 000 MW.

So far, there are only two important inter-connectors to Zimbabwe and the Democratic Republic of Congo (DRC) which are the most important electricity export grids.

Apart from the Kabompo power project which was recently commissioned, other projects aimed at averting power deficit include the 120 MW Itezhi-tezhi power project, rehabilitation of the 360 MW Kariba North Bank Station and the 750MW Kafue Gorge Lower project.

Under the Power Rehabilitation Project (PRP) by Zesco, the projects involved the rehabilitation and up rating of the three major hydro power stations namely, Kafue Gorge, Kariba North Bank and Victoria Falls.

The major achievements of the PRP has been the rehabilitation and upgrading of the Kafue Gorge Power Station from 900 to 990MW, the reinstating of the Victoria Falls Power Station to its full generating capacity of 108 MW as well as the up-rating of the Kariba North Bank power station from 600 MW to 720 MW.

6

Peat

Contents

Strategic insight

1. Introduction

Peat is the surface organic layer of a soil, consisting of partially decomposed organic material, derived mostly from plants, that has accumulated under conditions of waterlogging, oxygen deficiency, acidity and nutrient deficiency. In temperate, boreal and sub-arctic regions, where low temperatures (below freezing for long periods during the winter) reduce the rate of decomposition, peat is formed from mosses, herbs, shrubs and small trees (Joosten & Clarke, 2002). In the humid tropics, it is formed from rain forest trees (leaves, branches, trunks and roots) under near constantly high temperature (Page et al., 1999).

Peatlands are areas of landscape, with or without vegetation, that have a naturally accumulated peat layer at the surface. (Figures 6-1 and 6-2). For land to be designated as peatland, the thickness of the peat layer must be at least 20 cm if drained, and 30 cm if undrained. Peatland reserves are most frequently quoted on an area basis because initial inventory normally arises through soil survey or remote sensing. Even where peat deposit thickness 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. The organic component of peat deposits has, however, 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.

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

Figure 6-1
Cranberry Moss, a natural Peatland in the Midlands of England
Source: Jack Rieley

Figure 6-2
Undrained peat swamp forest in Central Kalimantan, Indonesia
Source: Jack Rieley

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 mostly during the Holocene epoch (the last 10 000 years), after the retreat of the glaciers that once covered most parts of the Northern Hemisphere. Those plant species, which formed the basal peat, are still forming peat today.

2. Technical and economic considerations

Resources

The estimation of peat resources on a global scale is difficult and data for many countries are imprecise or only partially ascertained. Never the less it is clear that the world possesses huge reserves of peat overall (Figure 6-3 overleaf). The total area of pre-disturbance peat-land, based on reports from WEC Member Committees and published sources notably, Immirzi et al. (1992) and Joosten & Clarke (2002), is about (4 million km^2, equivalent to 3% of the world's land surface (Table 8-1). Most of the world's peatland is in North America and the northern parts of Asia with large areas in northern and central Europe and in Southeast Asia, whilst some are in tropical Africa, Latin America and the Caribbean (Table 8-2). 85% of the global peatland area is in only four countries, Russia, Canada, USA and Indonesia. Large areas of peatland in Europe, totalling 450 000 km^2 (11 % from the total global area), have been utilised for centuries for agriculture and forestry (Figure 8-4). According to Immirzi et al. (1992), 40% of the peatland area in Europe and 5% overall in the rest of the world has been used in these ways although, since their assessment was published, large areas of peatland in Indonesia and Malaysia have been deforested, drained and converted to agriculture for arable crops and plantations. A relatively small area (5 000 km^2 or only 0.1 % of the total peatland area) has been used to extract peat for energy, horticulture and a range of other industrial and medical uses (Figure 6-4).

Figure 6-3
Global distribution of mires
Source: International Peat Society

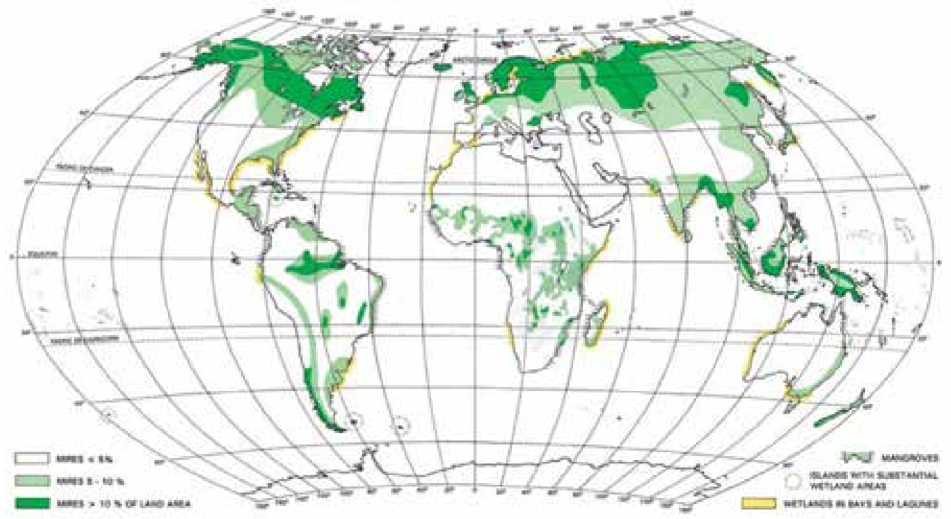
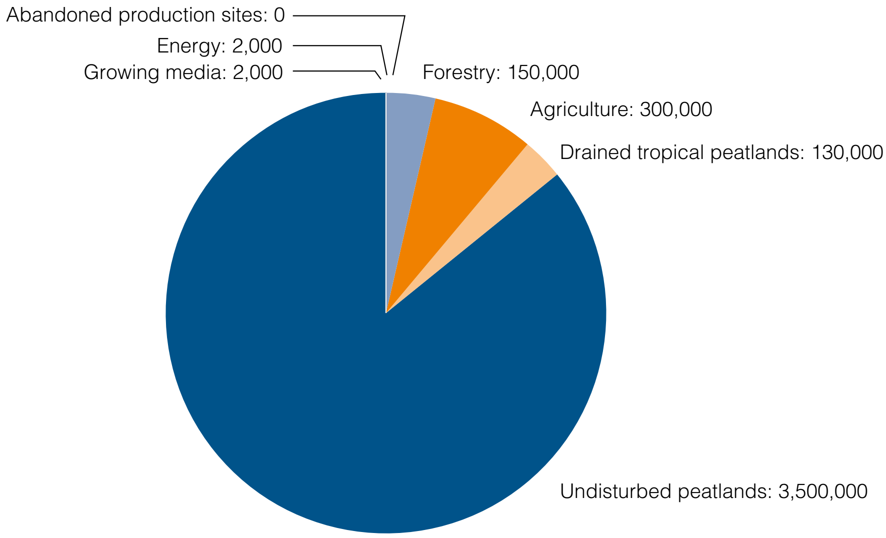


Figure 6-4
Uses of peatland
Source: International Peat Society



The average thickness of the peat layer is difficult to determine precisely owing to a lack of data for most countries. This makes it virtually impossible to determine accurately the overall volume of peat and therefore the amount of carbon it contains. Immirzi et al., (1992) used an estimated global mean thickness of 1.5 metres while Gorham (1991) used 2.3 for boreal and subarctic peatlands. The thickness of tropical peatland is likely to be greater. An indicative estimate of the total volume of peat in situ is in the order of 6,000 to 13,800 billion m^3, containing 300 to 695 billion tonnes (109) of carbon. According to Strack (2008) the global peat carbon pool is in the region of 500 billion tonnes. The peat reserve base in major extraction (mainly for energy and horticulture) countries (including 'reserves currently under active cultivation or economically recoverable under current market conditions') has been assessed (Couch, 1993) as 5,267 million tonnes (air-dried).

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 grind the top layer of the peat bog surface)) (Figures 6-5 and 6-6). Peat in situ contains

Figure 6-5
Peat milling machine. A 25-40 mm layer is removed from the surface of the peat production site and dried in the sun
Source: Association of Finnish Peat Industries

Figure 6-6
After milling peat is turned 3-5 times to speed up the drying process.
Source: Association of Finnish Peat Industries

around 90% water; some of which is removed by drainage and most of the remainder by drying in the sun and wind. The resulting 'air-dried' peat has a moisture content of 40-50%. The bulk of peat production for energy use is obtained by milling and used in electricity or heat generation. A proportion of the milled peat is converted into briquettes, which provide a convenient household fuel. The main countries producing and using fuel peat are Belarus, Estonia, Finland, Indonesia, Ireland, Russian Federation and Sweden (Table 6-3).

3. Market trends and outlook

Uses of Peat

Peat has a large number of uses, which may be classified under three headings:

- Energy (as fuel for electricity/heat generation, and directly as a source of heat for industrial, residential and other purposes) (Figures 6-7 and 6-8 – see page 5);
- Horticultural and agricultural (e.g. as growing medium, soil improver, cowshed/stable litter, compost ingredient);
- Other (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).

The report: "Fuel Peat industry in EU" (Paappanen, Leinonen and Hillebrand, 2006) summaries fuel peat utilization in European Union fuel peat countries as follows (Table 6-4):

> *"The total annual peat use during the 2000´s has been 3 370 ktoe. The three largest users are Finland (59 % of total use), Ireland (29%) and Sweden (11%), corresponding to 99% of the total use. Peat is used in central heating power plants (CH) (45% of the total use), in condensing power generation (CP) (38%), district heating (DH) (10%) and residential heating (RH) (8%). The total number of power plants is 125. The approximate number of people receiving heating energy from peat is 1.94 million.*

Figure 6-7
Greenhouses in Finland heated with sod peat
Source: Association of Finnish Peat Industries

Figure 6-8
Forssan Energia, Finland, uses both peat and wood-based fuels in combined heat and power production.
Source: Association of Finnish Peat Industries

Figure 6-9
Drained and burned peat swamp forest in Central Kalimantan, Indonesia.
Source: Jack Rieley

The total annual value of fuel peat sales is 390 million Euros. The total employment effect of peat production and use is 13 100 – 16 100 man years, including direct and indirect employment.

The total primary energy consumption in the six EU countries mentioned in the Report is approximately 120 Mtoe of which about 3.8 Mtoe is produced with peat. Therefore the overall share of peat of primary energy consumption is 3% in these countries.

In Finland and in Ireland about 5–7% of primary energy consumption relies on peat. In Estonia and Sweden this share is 1.9% and 0.7% respectively. In Latvia and Lithuania peat makes a smaller contribution to primary energy consumption.

The importance of peat at national level is most significant in Finland, where over 22% of all fuel used by CH plants is peat. In DH plants this share is 19%, and 8% for CP generation. The use of peat and wood is bound together. Owing to technical and economic reasons peat cannot be replaced fully with wood or other renewable or recyclable fuels. Peat also decreases the dependence of energy production on imported fuels. The only alternative to peat is coal, which cannot replace all of the peat, because of the technical characteristics of boilers.

In Ireland, that does not have any fossil fuel reserves, peat is an important source of domestic energy, and therefore it is included in the fuel mix. One of the principle energy sectors in Ireland is the electricity sector and of this peat contributes 8.5%. In Estonia about 4% of district heat is produced using peat. In Sweden the importance of peat at a national level is relatively low, 0.7% of primary energy consumption, but of CH and DH the peat share is 4% and 6%, respectively.

The regional benefits of peat production are mostly directed to rural areas, which suffer from migration of young people and from a workforce with a high average age, as well as from relatively low levels of income. Peat contractors usually also practice agriculture or forestry or some kind of contracting work. Therefore peat brings extra income to people and regions that are less developed economically.

Peat has both a short-term and a long-term role in security of energy supply. For example in Finland and Estonia the reserve supplies correspond to 7–17 months use, which can easily cover short-term interruptions in energy supply."

Peat from a Climate Impact Point of View

The Intergovernmental Panel on Climate Change (IPCC) changed the classification of peat from fossil fuel to a separate category between fossil and renewable fuels (25th session of IPCC, Port Louis, Mauritius, 2006). Peat now has its own category: 'peat'. The emission factor of peat is similar to fossil fuels.

Strategy for Responsible Peatland Management

In 2010, the International Peat Society (IPS) launched a globally applicable "Strategy for Responsible Peatland Management". The two-year development process for the Strategy included collaboration with a wide range of interested parties, including universities, the peat-producing and using industry and several non-government organisations.

The Strategy (SRPM) is now widely used in national policy development as well as a basis for several peatland certification schemes, such as Veriflora in Canada, the voluntary Code of Conduct of the European Peat and Growing Media Association (EPAGMA) and a special certification project for peat used in horticulture currently being planned in the Netherlands.

The main objective of the SRPM is to manage peatlands responsibly for their, environmental, social and economic values, according to the following priorities:

- Biodiversity
- Hydrology and water regulation
- Climate and climate change processes
- Economic activities
- After-use, rehabilitation and restoration
- Human and institutional capacity and information dissemination
- Engagement of local people
- Good governance

The Responsible Peatland Management Strategy encompasses all uses of peatlands and includes nature conservation and protection, various forms of economic use, as well as recreational and traditional uses. It sets out practical objectives for peatland management applicable at several levels (global, regional, national and sub-national) and identifies actions that will contribute to responsible management of peatlands.

By presenting commonly accepted principles, it provides a framework for the future development of a more detailed standard for peatland management to be used in voluntary certification. For more information, please visit www.peatsociety.org.

Balance of Peat Usage and Life-Cycle Analysis

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 fuel 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 World is estimated to be 100 million tonnes annually (Strack, 2008), thus exceeding the annual use of peat 3 to 6 times, although areas where peat is accumulating are not necessarily the same as those being used. Peat extraction and peat accumulation may be in global balance but this is not necessarily so on a country or regional basis.

Many peatlands globally, 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 by rewetting them. They could be restored to peat-forming mires, reclaimed to forests or planted with energy crops. These new carbon sinks 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.

Wise Use of Peat

The International Peat Society (IPS) joined 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 to adopt the 'Wise Use' approach and will mean that most of the remaining peat bogs in Europe and North America will not be utilised (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 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 as a result of large scale land use change and fire (Figure 8-7). 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 environment as a result of forest and peat fires in Indonesia in just 4 months (Page, et al. 2002). Since then, it is estimated that an average of around 2 billion tonnes of CO_2 have been released every year from peatland in Southeast Asia, as a result of peatland deforestation, drainage, degradation and conversion to oil palm and paper pulp tree plantations (Figure 8-9). This is equivalent to about 30% of global CO_2 emissions from fossil fuels (Hooijer, et al., 2006). Developed countries should assist in the wise use of tropical peatlands in agriculture and forestry, in order to prevent thoughtless release of CO_2 into the atmosphere. From a climate-impact point of view peat is much more acceptable than fossil fuels and if peat can be used in a wise way this will be to the benefit of mankind now and in the future.

Jack Rieley, Jaakko Silpola and Susann Warnecke
International Peat Society

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Web sites for further information

International Peat Society www.peatsociety.org
World Resources Institute www.wri.org

Global tables

Table 6.1
Peat: areas of peatland (square kilometres)

Russian Federation	1 390 000
Canada	1 113 280
United States of America	625 001
Indonesia	206 950
Finland	89 000
Sweden	66 000
China	53 120
Peru	50 000
Norway	28 010
United Kingdom	27 500
Malaysia	25 889
Brazil	23 875
Belarus	23 500
Germany	13 000
Poland	12 500
Zambia	12 201
Ireland	11 800
Falkland Islands	11 510
Papua New Guinea	10 986
Chile	10 472
Venezuela	10 000
Sudan	9 068
Estonia	9 020
Guyana	8 139
Iceland	8 000
Ukraine	8 000
Panama	7 870
Uganda	7 300
Cambodia	7 000
Latvia	6 600
Congo (Brazzaville)	6 220
Cuba	5 293
Colombia	5 043
Ecuador	5 001
Honduras	4 530
Nicaragua	3 710
New Zealand	3 610
Lithuania	3 520
Antarctica	3 000
Congo (Democratic Rep.)	2 800
Botswana	2 625
Kenya	2 440
Argentina	2 400

Japan	2 000
Guinea	1 952
Madagascar	1 920
French Guiana	1 620
Nigeria	1 600
France	1 500
Zimbabwe	1 400
Denmark	1 400
Korea (Democratic People's Rep.)	1 360
Australia	1 350
Myanmar (Burma)	1 228
Surinam	1 130
Cameroon	1 077
Mexico	1 000
Uruguay	1 000
Romania	1 000
Brunei	909
Rwanda	830
Belize	735
Côte d'Ivoire	725
Philippines	645
Thailand	638
Mozambique	575
Gabon	548
Vietnam	533
Bolivia	509
Malawi	492
Mali	400
India	400
Bangladesh	375
Costa Rica	370
Hungary	330
Burundi	323
South Africa	300
Italy	300
Serbia and Montenegro	300
Switzerland	300
Angola	264
Ethiopia	200
Georgia	200
Laos	200
Austria	200
Czech Republic	200
Albania	179
Belgium	160
Sri Lanka	158
Bosnia-Herzogovina	150
Jamaica	128
Liberia	120
Haiti	120
Afghanistan	120
Turkey	120
Benin	100

Central African Republic	100
Gambia	100
Tanzania	100
Puerto Rico	100
Paraguay	100
Kyrgyzstan	100
Pakistan	100
Slovenia	100
Iraq	100
El Salvador	90
St Helena	80
Greece	71
Mauritania	60
Spain	60
Ghana	59
Armenia	55
Kazakhstan	50
Mongolia	50
Egypt (Arab Rep.)	46
Israel	40
Fiji	40
Senegal	36
Micronesia	33
Niger	30
Faroe Islands	30
Macedonia (Rep.)	30
Slovakia	26
Bulgaria	25
Lesotho	20
Portugal	20
Algeria	10
Burkina Faso	10
Chad	10
Morocco	10
Namibia	10
Togo	10
Bahamas	10
Dominican Republic	10
Trinidad & Tobago	10
Azerbaijan	10
Moldova	10
Iran (Islamic Rep.)	10
Solomon Islands	10
Greenland	5
Korea (Republic)	5
Andorra	5
Luxembourg	3
Syria (Arab Rep.)	3
Guadeloupe	2
Kiribati	2
Mauritius	1
Réunion	1
Sierra Leone	1

Tunisia	1
Bermuda	1
Dominica	1
Martinique	1
St Kitts & Nevis	1
Guatemala	1
Bhutan	1
Cyprus	1
Maldives	1
Nepal	1
Singapore	1
Azores	1
Croatia	1
Liechtenstein	1
Jordan	1
Lebanon	1
Palau	1
Samoa	1
World Total	**3 973 503**

Table 6.2
Global peatland area by region

Sources: Immirzi et al. (1992); Joosten and Clarke (2002); www.carbopeat.org

Region	Peatland Area (km2)
Central and North America	1,762,267
Asia	1,490,361
Europe	525,668
South America	130,800
Africa	56,165
Antarctica, Oceania, Pacific	8,048
TOTAL	3,973,309
Tropical peatland	41,547

Table 6.3
Peat: production and consumption for fuel in 2008 (provisional)

	Source	Production (thousand tonnes)	Consumption (thousand tonnes)
Burundi	www	20	20
Total Africa		20	20
Falkland Islands	estimated	13	13
Total South America		13	13
Austria	IEA	1	1
Belarus	www / IEA (2007)	2 944	2 240
Estonia	Statistics Estonia	214	294
Finland	IEA	4 770	7 910
Germany	IEA		
Ireland	IEA	3 089	4 140
Latvia	Eurostat	11	11
Lithuania	Eurostat	58	36
Romania	IEA (2007)	1	25

Russian Federation	IEA (2007)	1 287	1 176
Sweden	IEA	701	1 065
Ukraine	IEA (2007)	395	383
United Kingdom	Estimated	20	20
Total Europe		13 491	17 301
TOTAL WORLD		**13 524**	**17 334**

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. Tonnages are generally expressed in terms of air-dried peat (35%-55% moisture content)
3. Sources: *Energy Statistics of OECD Countries*, 2009 Edition, International Energy Agency; *Energy Statistics of Non-OECD Countries*, 2009 Edition, International Energy Agency; Eurostat; web sites; estimates by the Editors
4. Differences between production and consumption can be due to two factors: (i) import and export of peat and (ii) and peat may be stored between years since production can vary significantly between years as a result of differences in weather conditions during the harvesting season.

Table 6.4
Fuel Peat industry in the EU

Source: Paappanen et al., 2006

	Finland	Ireland	Sweden	Estonia	Latvia	Lithuania	Total
"Fuel peat resources, ktoe"	1,100,000	47,500	370,000	10,000	57,000	4,000	1,589,000
"Annual peat use, ktoe"	1980	984	372	28	0	4	3368
"Number of peat producers"	250	300	25	30	11	11	630
Number of machine and boiler manufacturers	22	1	9	9	0	0	41
"Number of peat-fired power plants"	55	3	20	40	0	7	125
"Number of people getting heating energy from peat"	480,000	1,000,000	390,000	65,000	0	0	1,940,000
"Value of domestic trade, million Euro"	204	153	27	2	0	3	390
"Value of international trade, million Euro"	0.5	0.0	16.9	7.1	0.3	0.2	17.9
"Employment, man-years"	7000	2300	1700	2100	0	0	13100

Country notes

The following Country Notes on Peat provide a brief account of countries with significant peat 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.

Argentina

Areas of peatland (square kilometres)	2 400
Production (thousand tonnes)	8

The main (about 95%) of peat deposits in Argentina are located on the Isla Grande de Tierra del Fuego in the South of the country. The remaining peat bogs can be found in the highland valleys of the Andean Cordillera and other areas. Production of peat is on a relatively small scale and nearly totally confined to Tierra del Fuego, where circa 3 000 m3 per annum are extracted. Consumption of peat for energy production is currently insignificant, and currently peat is mainly used is as a soil-improvement agent.

Proved recoverable reserves of peat are reported by the Argentinian Member Committee to be 80 million tonnes, within a total proved amount in place of some 90 million tonnes. A further 50 million tonnes of (unproved) resources is estimated to be present, of which some 15 million tonnes is deemed to be recoverable

Belarus

Areas of peatland (square kilometres)	23 500
Production (thousand tonnes)	2.2
Consumption (thousand tonnes)	2

Belarus has the largest peat lands in Eastern Europe (after Russian Federation), amounting to 23 500 km^2. The main areas of peat formation are located in the Pripyat Marshes in the South and in the central area around Minsk. Peat has been used in Belarus as a fuel for many years, with the peak consumption during the 1970’s and 1980’s. However, since 1986 peat has no longer been used as a fuel for power generation; and the largest part of output in recent years has been used for the production of peat briquettes, mainly for household use.

Out of a total fuel peat production of around 3 million tonnes per annum, briquetting plants account for about 2 million tonnes. heat plants for about 300 000 tpa, with the balance either being exported or consumed by a variety of small-scale consumers. Current annual output of peat briquettes is approximately 1.7 million tonnes, of which about 78% is consumed by residential users.

Brazil

Areas of peatland (square kilometres)	23 875
Production (thousand tonnes)	2500
Consumption (thousand tonnes)	

The total area of peat land in Brazil is estimated to be nearly 24 000 km^2, the second largest in South America after Peru. There are large peat deposits in the Middle Amazon and in a large marshy plain (Pantanal) near the Bolivian border. Smaller areas of peatland are located in coastal areas. Peat lands 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. These areas have recently attracted interest as potential sites for the production of peat for energy uses. Experts from 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 established.

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

Areas of peatland (square kilometres)	323
Production (thousand tonnes)	11
Consumption (thousand tonnes)	6

The National Peat Office (ONATOUR) in the country has the mission to exploit and commercialise production and use of peat; primarily in industry and agriculture and conduct further research and studies of the peat potential. Peat has been known in Burundi since the time the country was under Belgian control. Exploitable reserves have been estimated at 57 million tonnes at 30% humidity in an area of around 150 km^2.

ONATOUR is the only enterprise in the Great Lakes region of Africa that mechanically produces peat sods. Since it was established in 1977, 300 000 tonnes, some 0.5% of reserves, have been processed. The major users of peat are military camps and prisons, which account for 90% of production. The remaining 10% is lost during handling or stockpiling. ONATOUR has sold nearly 225 000 tonnes of peat since its formation, with the army being the principal client. Following the acquisition of new production installations, production of peat is expected to increase.

Canada

Areas of peatland (square kilometres)	1 113 280
Production (thousand tonnes)	
Consumption (thousand tonnes)	

Canada’s peatlands are estimated to exceed 1.1 million km^2, globally second only to those of the Russia Federation.

There have been a number of assessments of the potential use of peat as a fuel (including for power generation) but at present, peat is not used for energy purposes and it is unlikely to change in the immediate future. Canada is, however, a major producer (and exporter) of peat for horticultural applications.

China

Areas of peatland (square kilometres)	53 000
Production (thousand tonnes)	
Consumption (thousand tonnes)	

China's peatlands total about 53 000 km^2 and are widely distributed across the country. However, peatlands occupy only about 0.5% of the country's land area, and thus are insignificant to the country's topography. The principal peat areas are located in the region of the Qing-zang Plateau in the southwest, in the north-east mountains and in the lower Yangtze plain in the east.

Peat has been harvested since the 1970s for a variety of purposes, including fuel use. Some peat 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.

Denmark

Areas of peatland (square kilometres)	1 000
Production (thousand tonnes)	300
Consumption (thousand tonnes)	

Human activities, mainly cultivation and drainage operations, have reduced Denmark's originally extensive areas of peatland from some 20-25% of its total land area to not much more than 3% today. Out of a total existing mire area of 1 400 km^2, freshwater peatland accounts for about 1 000 km^2; the remainder consists 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.

Estonia

Areas of peatland (square kilometres)	9 070
Production (thousand tonnes)	
Consumption (thousand tonnes)	

Peatlands are a major feature of the topography in Estonia, occupying about 20% of its total territory. Peatlands 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.

Annual use of peat for fuel has averaged about 350 000 tonnes in recent years but, as in other countries, tends to be highly variable. In thousands of tonnes, A considerable proportion of peat is used to produce briquettes, most of which are destined for export. In 2007, briquette production totalled 128 000 tonnes, of which 75% was exported, the balance being very largely consumed in the residential sector. As a consequence of the low peat harvest in 2008, output of briquettes in that year was nearly halved. Exports of peat briquettes, however, fell by only 5 000 tonnes, whilst domestic consumption actually increased. This was possible through a substantial drawdown in stocks of briquettes, which fell by 40 000 tonnes.

Most of the consumption of un-briquetted peat is accounted for by district heating and electricity generation (mainly CHP). Some sod peat (27 000 tonnes in 2008) is exported, but annual amounts are highly variable.

Finland

Areas of peatland (square kilometres)	89 000
Production (thousand tonnes)	8.9
Consumption (thousand tonnes)	61

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 2009, the total area used for peat production was about 630 km^2. The energy content of peat technically suitable for extraction is about 12 800TWh, while the amount of fuel peat consumption has recently varied between 10 and 30TWh/yr.

According to the Association of Finnish Peat Industries, quoted by Statistics Finland, 2008 peat production in Finland – the latest available – rose by nearly 7%. However, 2007 peat production was 66% lower than in the previous year, whereas Finnish consumption of peat fuel grew by about 9% in 2007 over 2006. This apparent discrepancy between supply and demand is an excellent illustration of one of peat's special features. Owing to the vagaries of the weather, in particular the amount of sunshine, wind and rainfall during the peat harvesting, milling and drying season, annual production levels vary greatly. In order to cope with such circumstances, the principal peat-consuming countries maintain large buffer stocks, which enable them to smooth out supplies to power plants and other consumers.

In 2007, CHP plants accounted for almost 52%, and power stations for 30%, of the total national consumption of fuel peat; industrial users consumed 12%, the balance being used in heat plants (5%), and directly in the residential and agricultural sector (1%). The share of peat fuel was about 7% of total energy consumption.

The Keljonlahti hybrid CHP plant (200 MW heat, 210 MW electricity) has been brought into operation in Jyväskylä. The plant uses about 1 million tonnes of wood and peat each year.

Germany

Areas of peatland (square kilometres)	14 000
Production (thousand tonnes)	
Consumption (thousand tonnes)	

The majority of the peatlands are located in the north of Germany such as Lower Saxony, Mecklenburg-West Pomerania and Brandenburg. The German WEC Member Committee reports a total peatland area of some 14 000 km^2 and the proved amount of peat in place is 157 million tonnes, of which about 23% is considered to be recoverable.

Approximately 60% is farmed, with only a small proportion (less than 10%) used for peat production. Energy use of peat is reported to be very limited at present, virtually all production being destined for agricultural/horticultural uses or for the manufacture of activated carbon. A small amount of energy-grade peat is exported.

Greece

Areas of peatland (square kilometres)	55
Production (thousand tonnes)	
Consumption (thousand tonnes)	

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

Areas of peatland (square kilometres)	8 000
Production (thousand tonnes)	
Consumption (thousand tonnes)	

Peatlands cover 8 000 km^2 or about 8% 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

Areas of peatland (square kilometres)	206 950
Production (thousand tonnes)	
Consumption (thousand tonnes)	

The peatlands are by far the most extensive in the tropical zone (estimated at 207 000 km^2) and rank as the fourth 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

Areas of peatland (square kilometres)	11 760
Production (thousand tonnes)	2.7
Consumption (thousand tonnes)	539

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 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 2008 (as reported to the IEA) was about 3.1 million tonnes, with consumption of around 4.1 million tonnes.

Out of the total production of peat for energy purposes in 2007, nearly 67% was used for power generating and heat production, 14% was briquetted and 17% consisted of sod peat, used predominantly as a residential fuel. Peat briquettes are almost entirely 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 generating 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 Clonbullοge, 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 2.5 to 4.2 million tonnes, with an average annual level of just under 3.4 million tonnes. Sales of milled peat to power stations rose from just under 2 million tonnes in 2004/05 to nearly

3.1 million tonnes in 2008/09, in line with the input capacity (quoted above) of the three new peat-fired plants.

In 2008/09, 882 000 tonnes of milled peat were consigned to Bord na Móna's briquetting plants, which produced 217 000 tonnes of peat briquettes during the same period; these levels were close to the five-year averages of 903 000 and 219 000 tonnes respectively.

Italy

Areas of peatland (square kilometres)	300
Production (thousand tonnes)	
Consumption (thousand tonnes)	

There are significant resources of peat in Italy, mostly in the north of the country in areas such as Piedmont, Lombardia and Venezia. Fuel Peat: World Resources and Utilisation gives the estimated reserves as 2.5 billion tones, however the proportion of this that is usable is yet to be determined.

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

Areas of peatland (square kilometres)	11 400
Production (thousand tonnes)	25
Consumption (thousand tonnes)	1

Peatlands cover an estimated 6 600 km^2, or about 10% of Latvia's territory, with the major deposits 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

Areas of peatland (square kilometres)	6 600
Production (thousand tonnes)	53
Consumption (thousand tonnes)	5

Peatlands (totalling about 3 500 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 then consumption has declined further to around 65 000 tonnes per year. The principal peat consumers are heat plants, producers of semi-briquettes, and households. They also account for virtually all of Lithuania's modest consumption of locally-produced peat semi-briquettes, together with briquettes imported from Belarus (8 000 tonnes in 2007).

Norway

Areas of peatland (square kilometres)	28 010
Production (thousand tonnes)	
Consumption (thousand tonnes)	

Although there are extensive areas of essentially undisturbed peatland, amounting to some 28000 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

Areas of peatland (square kilometres) 12 500	
Production (thousand tonnes)	
Consumption (thousand tonnes)	

The area of peatland is some 12500 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

Areas of peatland (square kilometres)	1 000
Production (thousand tonnes)	9
Consumption (thousand tonnes)	

There are estimated to be 1000 km^2 of peatlands. Peat production for energy purposes has dwindled to a very low level; annual consumption of around 40 000 tonnes is largely met by imports.

Russian Federation

Areas of peatland (square kilometres)	1 390 000
Production (thousand tonnes)	910
Consumption (thousand tonnes)	10

The total area of peatlands in Russia has been estimated at some 1 390 000 km^2, of which 85% are located in Siberia.

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%.

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

Areas of peatland (square kilometres)	66 000
Production (thousand tonnes)	702
Consumption (thousand tonnes)	

In Western Europe, the extent of Sweden's peatlands (66 000 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.

The use of peat as a household fuel has never been of much significance in Sweden. 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 2007, CHP plants accounted for 73% of total consumption, heat plants for 23% and industrial users for the remainder.

Sweden's reliance on peat as a fuel is considerably lower than that of Finland or Ireland, and moreover it imports about a third of its requirements, chiefly from Belarus, Latvia and Estonia. The Swedish Peat Producers Association forecasts that over the longer term peat imports will tend to decrease, as the Baltic States will need to increase their use of indigenous fuels in the face of rising natural gas prices, particularly following the commissioning of the North Stream pipeline between Russia and Germany. The Association considers that Sweden needs to produce more of its own fuel peat, but reports that there are problems in obtaining licences, on account of a resistance to peat production. It states that its biggest problem is achieving greater public acceptance of peat as a fuel. The Government's energy and climate policy (February 2009) points out that 'under certain conditions and to a limited extent, peat can be used with a positive net climate impact'. It therefore considers that Sweden should take action to ensure that this point is taken into account by the IPCC and in the EU's regulatory framework

Ukraine

Areas of peatland (square kilometres)	10 000
Production (thousand tonnes)	449
Consumption (thousand tonnes)	8

There are estimated to be 10 000 km^2 of peatlands, more than half of which are located in Polesie, in the north of the country. 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 350 000 tonnes per annum, the bulk of which is consumed by households, either directly or in the form of peat briquettes

United Kingdom

Areas of peatland (square kilometres)	17 500
Production (thousand tonnes)	
Consumption (thousand tonnes)	

The peatlands of UK cover an area of some 17 500 km^2, most deposits being in the northern and western regions.

The total UK peatland area is more than twice that of Ireland, but the extraction of peat is on a very much smaller scale. 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.

United States of America

Areas of peatland (square kilometres)	6 250 001
Production (thousand tonnes)	
Consumption (thousand tonnes)	

The area of peatlands in the USA has been estimated at some 625 000 km^2, the majority of which is located in Alaska. 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.

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Bioenergy

Contents

Strategic insight

1. Introduction

The supply of sustainable energy is one of the main challenges that mankind will face over the coming decades, particularly because of the need to address climate change. Biomass can make a substantial contribution to supplying future energy demand in a sustainable way. It is presently the largest global contributor of renewable energy, and has significant potential to expand in the production of heat, electricity, and fuels for transport. Further deployment of bioenergy, if carefully managed, could provide:

- an even larger contribution to global primary energy supply;
- significant reductions in greenhouse gas emissions and potentially other environmental benefits;
- improvements in energy security and trade balances, by substituting imported fossil fuels with domestic biomass;
- opportunities for economic and social development in rural communities;
- scope for using wastes and residues, reducing waste disposal problems and making better use of resources.

This commentary provides an overview of the potential for bioenergy and the challenges associated with its increased deployment. It discusses opportunities and risks in relation to resources, technologies, practices, markets and policy. The aim is to provide insights into the opportunities and required actions for the development of a sustainable bioenergy industry. at present, forestry, agricultural and municipal residues, and wastes are the main feedstocks for the generation of electricity and heat from biomass. In addition, very small shares of sugar, grain, and vegetable oil crops are used as feedstocks for the production of liquid biofuels. Today, biomass supplies some 50 EJ globally, which represents 10% of global annual primary energy consumption.

This is mostly traditional biomass used for cooking and heating

There is significant potential to expand biomass use by tapping the large volumes of unused residues and wastes. The use of conventional crops for energy use can also be expanded, with careful consideration of land availability and food demand. In the medium term, lignocellulosic crops (both herbaceous and woody) could be produced on marginal, degraded and surplus agricultural lands and provide the bulk of the biomass resource. In the longer term, aquatic biomass (algae) could also make a significant contribution. Based on this diverse range of feedstocks, the technical potential for biomass is estimated in the literature to be possibly as high as 1 500 EJ/yr by 2050, although most biomass supply scenarios that take into account sustainability constraints indicate an annual potential of between 200 and 500 EJ/yr (excluding aquatic biomass). Forestry and agricultural residues and other organic wastes (including municipal solid waste) would provide between 50 and 150 EJ/yr, while the remainder would come from energy crops, surplus forest growth, and increased agricultural productivity.

Projected world primary energy demand by 2050 is expected to be in the range of 600 to 1 000 EJ (compared to about 500 EJ in 2008). Scenarios looking at the penetration of different

Figure 9.1
Share of bioenergy in the world primary energy mix

Source: based on IEA, 2006; IPCC, 2007

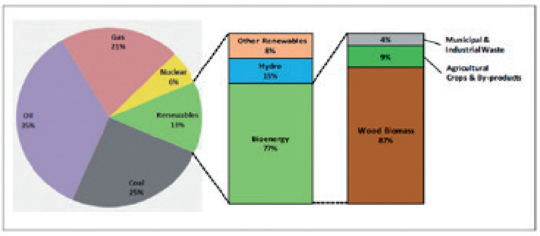
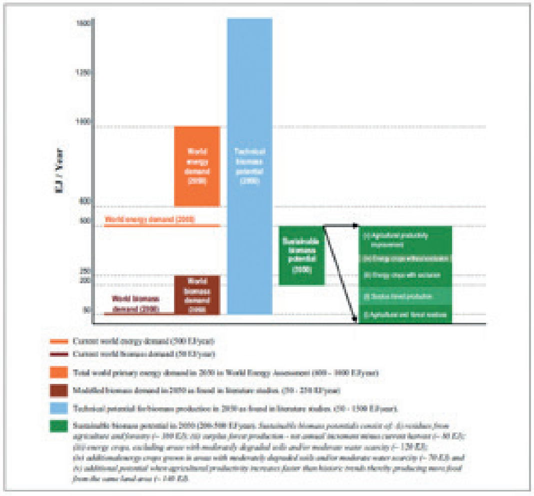


Figure 9.2
Technical and sustainable biomass supply potentials and expected demand

Source: adapted from Dornburg, et al. [2008], based on several review studies



low-carbon energy sources indicate that future demand for bioenergy could be up to 250 EJ/yr. This projected demand falls well within the sustainable supply potential estimate, so it is reasonable to assume that biomass could sustainably contribute between a quarter and a third of the future global energy mix (Fig. 9.2).

Whatever is actually realised will depend on the cost competitiveness of bioenergy and on future policy frameworks, such as greenhouse gas emission reduction targets. Growth in the use of biomass resources in the mid-term period to 2030 will depend on many demand and supply side factors. Strong renewable energy targets being set at regional and national level (e.g. the European Renewable Energy Directive) are likely to lead to a significant increase in demand. This demand is likely to be met through increased use of residues and wastes, sugar, starch and oil crops, and increasingly, lignocellulosic crops. The contribution of energy crops depends on the choice of crop and planting rates, which are influenced by productivity increases in agriculture, environmental constraints, water availability and logistical constraints. Under favourable conditions substantial growth is possible over the next 20 years. However, estimates of the potential increase in production do vary widely. For example, the biomass potential from residues and energy crops in the EU to 2030 is estimated to range between 4.4 and 24 EJ. The long-term potential for energy crops depends largely on:

- land availability, which depends on food sector development (growth in food demand, population diet, and increased crop productivity) and factors limiting access to land, such as water and nature protection;
- the choice of energy crops, which defines the biomass yield levels that can be obtained on the

Other factors that may affect biomass potential include the impact of biotechnology, such as genetically modified organisms, water availability, and the effects of climate change on productivity.

The uptake of biomass depends on several factors:

- biomass production costs – US$ 4/GJ is often regarded as an upper limit if bioenergy is to be widely deployed today in all sectors;

- logistics – as with all agricultural commodities, energy crops and residues all require appropriate supply chain infrastructure;
- resource and environmental issues – biomass feedstock production can have both positive and negative effects on the environment (water availability and quality, soil quality and these will result in regulations restricting or incentivising particular practices (e.g. environmental regulations, sustainability standards, etc.).

Drivers for increased bioenergy use (e.g. policy targets for renewables) can lead to increased demand for biomass, leading to competition for land currently used for food production, and possibly (indirectly) causing sensitive areas to be taken into production. This will require intervention by policy makers, in the form of regulation of bioenergy chains and/or regulation of land use, to ensure sustainable demand and production. Development of appropriate policy requires an understanding of the complex issues involved and international cooperation on measures to promote global sustainable biomass production systems and practices. To achieve the bioenergy potential targets in the longer term, government policies and industrial efforts need to be directed at increasing biomass yield levels and modernising agriculture in regions such as Africa, the Far East and Latin America, directly increasing global food production and thus the resources available for biomass. This can be achieved by technology development and by the diffusion of best sustainable agricultural practices. The sustainable use of residues and wastes for bioenergy, which present limited or zero environmental risks, needs to be encouraged and promoted globally.

Biomass Conversion Technologies

There are many bioenergy routes which can be used to convert raw biomass feedstock into a final energy product (Fig. 9.3). Several conversion technologies have been developed that are adapted to the different physical nature and chemical composition of the feedstock, and to the energy service required (heat, power, transport fuel). Upgrading technologies for biomass feedstocks (e.g. pelletisation, torrefaction and pyrolysis) are being developed to convert bulky raw biomass into denser and more practical energy carriers for more efficient transport, storage and convenient use in

The production of heat by the direct combustion of biomass is the leading bioenergy application throughout the world, and is often cost-competitive with fossil fuel alternatives. Technologies range from rudimentary stoves to sophisticated modern appliances. For a more energy efficient use of the biomass resource, modern, large-scale heat applications are often combined with electricity production in combined heat and power (CHP) systems.

Different technologies exist or are being developed to produce electricity from biomass. Co-combustion (also called co-firing) in coal-based power plants is the most cost-effective use of biomass for power generation. Dedicated biomass combustion plants, including MSW combustion plants, are also in successful commercial operation and many are industrial or district heating CHP facilities. For sludges, liquids and wet organic materials, anaerobic digestion is currently the best-suited option for producing electricity and/or heat from biomass, although its economic case relies heavily on the availability of low-cost feedstock. All these technologies are well established and commercially available.

There are few examples of commercial gasification plants, and the deployment of this technology is affected by its complexity and cost. In the longer term, if reliable and cost-effective operation can be more widely demonstrated, gasification promises greater efficiency, better economics at both smalland large-scale and lower emissions compared with other biomass-based power generation options. Other technologies (such as Organic Rankin Cycle and Stirling engines) are currently in the demonstration stage and could prove economically viable in a range of small-scale.

In the transport sector, first-generation biofuels are widely deployed in several countries, mainly bioethanol from starch and sugar crops and biodiesel from oil crops and residual oils and fats. Production costs of current biofuels vary significantly depending on the feedstock used (and their volatile prices) and on the scale of the plant. The potential for further deploying these first-generation technologies is high, subject to sustainable land-use criteria being met.

First-generation biofuels face both social and environmental challenges, largely because they use food crops which could lead to food price increases and possibly indirect land-use change. While such risks can be mitigated by regulation and sustainability assurance and certification, technology development is also advancing for next-generation processes that rely on non-food biomass (e.g. lignocellulosic feedstocks such as organic wastes, forestry residues, high-yielding woody or grass energy crops and algae). The use of these feedstocks for second-generation biofuel production would significantly decrease the potential pressure on land use, improve greenhouse gas emission reductions when compared to some first-generation biofuels, and result in lower environmental and social risk. Second-generation technologies, mainly using lignocellulosic feedstocks for the production of ethanol, synthetic diesel and aviation fuels, are still immature and need further development and investment to demonstrate reliable operation at commercial scale and to achieve cost reductions through scale-up and replication. The current level of activity in the area indicates that these routes are likely to become commercial over the next decade. Future generations of biofuels, such as oils produced from algae, are at the applied R&D stage, and require considerable development before they can become competitive contributors to the energy markets).

Further development of bioenergy technologies is needed, mainly to improve the efficiency, reliability and sustainability of bioenergy chains. In the heat sector, improvement would lead to cleaner, more reliable systems linked to higher-quality fuel supplies. In the electricity sector, the development of smaller and more cost-effective electricity or CHP systems could better match local resource availability. In the transport sector, improvements could lead to higher quality and more sustainable biofuels.

Ultimately, bioenergy production may increasingly occur in bio-refineries where transport biofuels, power, heat, chemicals and other marketable products could all be co-produced from a mix of biomass feedstocks. The link between producing energy and other materials deserves further attention technically and commercially.

The predominant use of biomass today consists of fuel wood used in non-commercial applications, in simple inefficient stoves for domestic heating and cooking in developing countries, where biomass contributes some 22% to the total primary energy mix. This traditional use of biomass is expected to grow with increasing world population. However, there is significant scope to improve its efficiency and environmental performance and thereby help reduce biomass consumption and related impacts.

In industrialised countries, the total contribution of modern biomass is on average only about 3% of total primary energy, and consists mostly of heat only and heat and power applications. Many countries have targets to significantly increase biomass use, as it is seen as a key contributor to meeting energy and environmental policy objectives. Current markets, growing as a result of attractive economics, mostly involve domestic heat supply (e.g. pellet boilers), large-scale industrial and community CHP generation (particularly where low-cost feedstocks from forest residues, bagasse, MSW etc. are available), and co-firing in large coalbased power plants. The deployment of dedicated electricity plants has been mainly confined to lowcost feedstocks in relatively small-scale applications, such as the use of biogas and landfill gas from waste treatment. Globally, the use of biomass in heat and industrial energy applications is expected to double by 2050 under business-as usual scenarios, while electricity production from biomass is projected to increase, from its current share of 1.3% in total power production to 2.4 – 3.3% by 2030 (corresponding to a 5 - 6% average annual growth rate).

Transport biofuels are currently the fastest growing bioenergy sector, receiving a great deal of public attention. However, today they represent only 1.5% of total road transport fuel consumption and only 2% of total bioenergy. They are, however, expected to play an increasing role in meeting the demand for road transport fuel, with second generation biofuels increasing in importance over the next two decades. Even under business-as usual scenarios, biofuel production is expected to increase by a factor of 10 to 20 relative to current levels by 2030 (corresponding to a 6 - 8% average annual growth rate).

Global trade in biomass feedstocks (e.g. wood chips, vegetable oils and agricultural residues) and processed bioenergy carriers (e.g. ethanol, biodiesel, wood pellets) is growing rapidly. Present estimates indicate that bioenergy trade is modest – around 1 EJ (about 2% of current bioenergy use). In the longer term, much larger quantities of these products might be traded internationally, with Latin America and Sub-Saharan Africa as potential net exporters and North America, Europe and Asia foreseen as net importers. Trade will be an important component of the sustained growth of the bioenergy sector

The quest for a sustainable energy system will require more bioenergy than the growth projected under the business-as-usual scenarios. A number of biomass supply chain issues and market risks and barriers will need to be addressed and mitigated to enable stronger sustained growth of the bioenergy sector. These include:

- ***Security of the feedstock supply*** - this is susceptible to the inherent volatility of biological production (due to weather and seasonal variations), which can lead to significant variations in feedstock supply quantity, quality and price. Risk mitigation strategies already common in food and energy markets include having a larger, more fluid, global biomass sector and the creation of buffer stocks.
- ***Economies of scale and logistics*** – many commercially available technologies suffer from poor economics at a small scale, but conversely larger scales require improved and more complex feedstock supply logistics. Efforts are required to develop technologies at appropriate scales and with appropriate supply chains to meet different application requirements.
- ***Competition*** - bioenergy technologies compete with other renewable and non-renewable energy sources and may compete for feedstock with other sectors such as food, chemicals and materials. Also, the development of second-generation biofuel technologies could lead to competition for biomass resources between bioenergy applications, and potentially with other industry sectors. Support needs to be directed at developing cost-effective bioenergy routes and at deploying larger quantities of biomass feedstocks from sustainable sources.
- ***Public and NGO acceptance*** - this is a major risk factor facing alternative energy sources and bioenergy in particular. The public needs to be informed and confident that bioenergy is environmentally and socially beneficial and does not result in significant negative environmental and social trade-offs. However, the industry is confident such challenges can be met as similar challenges have been addressed in other sectors and appropriate technologies and practices are being developed and deployed.

Interactions with Other Markets

Developments in the bioenergy sector can influence markets for agricultural products (e.g. food and feed products, straw) and forest products (e.g. paper, board). However, this impact is not straightforward, owing to:

- other factors, such as biomass yield variations and fossil fuel price volatilities influencing markets just as much or more than biomass;
- other policy domains, including forestry, agriculture, environment, transport, health and trade, also having influence on bioenergy policies;
- a lack of transparency in many product and commodity markets, especially in forest products, making it difficult to assess the impact of bioenergy development.

While all forms of bioenergy interrelate with agriculture and/or forest markets through their feedstock demand, the impact of first-generation liquid biofuels on food prices has been a topic of strong debate in recent years. Although different studies reveal a wide variety of opinions on the magnitude of these impacts, most model-based demand scenarios indicate a relatively limited risk of biofuels significantly affecting the price of food crops. In general, markets can work to dampen these effects.

Markets will need access to monetary and physical resources, and will need to function efficiently and transparently in order to counteract the pressure of increasing demand. There is therefore an important role for policy in providing support to an increasingly efficient industry, for example in terms of yields, use of residues and wastes, and land use, while providing regulation to avoid negative impacts associated with the exploitation of physical resources. This requires active coordination between energy, agriculture and forestry, trade and environmental policies.

Bioenergy can significantly increase its existing contribution to policy objectives, such as CO_2 emission reductions and energy security, as well as to social and economic development objectives.

Appreciating where bioenergy can have the greatest impact on GHG emissions reduction relies on both an understanding of the emissions resulting from different bioenergy routes and the importance of bioenergy in reducing emissions in a particular sector. Bioenergy chains can perform very differently with regard to GHG emissions. Substituting biomass for fossil fuels in heat and electricity generation is generally less costly and provides larger emission reductions per unit of biomass than substituting biomass for gasoline or diesel used for transport. However, the stationary bioenergy sector can rely on a range of different low-carbon options while biofuels are the primary option for decarbonising road transport until allelectric and/or hydrogen fuel cell powered vehicles become widely deployed, which is unlikely to be the case for some decades. In the long term, biofuels might remain the only option for decarbonising aviation transport, a sector for which it will be difficult to find an alternative to liquid fuels.

Land suitable for producing biomass for energy can also be used for the creation of biospheric carbon sinks. Several factors determine the relative attractiveness of these two options, in particular land productivity, including co-products, and fossil fuel replacement efficiency. Also, possible direct and indirect emissions from converting land to another use can substantially reduce the climate benefit of both bioenergy and carbon sink projects, and need to be taken into careful consideration. A further influencing factor is the time scale that is used for the evaluation of the carbon reduction potential: a short time scale tends to favour the sink option, while a longer time scale offers larger savings as biomass production is not limited by saturation but can repeatedly (from harvest to harvest) deliver greenhouse gas emission reductions by substituting for fossil fuels. Mature forests that have ceased to serve as carbon sinks can in principle be managed in a conventional manner to produce timber and other forest products, offering a relatively low GHG reduction per hectare. Alternatively, they could be converted to higher yielding energy plantations (or to food production) but this would involve the release of at least part of the carbon store created.

The use of domestic biomass resources can make a contribution to energy security, depending on which energy source it is replacing. Biomass imports from widely distributed international sources generally also contribute to the diversification of the energy mix. However, supply security can be affected by natural variations in biomass outputs and by supply-demand imbalances in the food and forest product sectors, potentially leading to shortages.

The production of bioenergy can also result in other (positive and negative) environmental and socioeconomic effects. Most of the environmental effects are linked to biomass feedstock production, many of which can be mitigated through best practices and appropriate regulation. Technical solutions are available for mitigating most environmental impacts from bioenergy conversion facilities and their vehicle fleets such as city buses have historically been diesel powered but are very suitable for the introduction of new fuels, e.g. biogas or ethanol. The performance and sustainability of liquid biofuels is a current RD&D focus. Their use is largely a question of appropriate environmental regulations and their enforcement. The use of organic waste and agricultural/forestry residues, and of lignocellulosic crops that could be grown on a wider spectrum of land types, may mitigate land and water demand and reduce competition with food.

Feedstock production systems can also provide several benefits. For instance, forest residue harvesting improves forest site conditions for planting, thinning generally improves the growth and productivity of the remaining stand, and removal of biomass from over-dense stands can reduce the risk of wildfire. In agriculture, biomass can be cultivated in so-called multifunctional plantations that – through well-chosen locations, design, management, and system integration – offer extra environmental services that, in turn, create added value for the systems.

Policy around bioenergy needs to be designed so that it is consistent with meeting environmental and social objectives. Bioenergy needs to be regulated so that environmental and social issues are taken into consideration, environmental services provided by bioenergy systems are recognised and valued, and so that it contributes to rural development objectives.

The deployment of many bioenergy options depends on government support, at least in the short and medium term, the design and implementation of appropriate policies and support mechanisms is vital, and defensible, particularly given the associated environmental benefits and existing government support for fossil fuels. These policies should also ensure that bioenergy contributes to economic, environmental and social goals. Experience over the last couple of decades has taught us the following:

A policy initiative for bioenergy is most effective when it is part of a long-term vision that builds on specific national or regional characteristics and strengths, e.g. in terms of existing or potential biomass feedstocks available, specific features of the industrial and energy sector, and the infrastructure and trade context.

Policies should take into account the development stage of a specific bioenergy technology, and provide incentives consistent with the barriers that an option is facing. Factors such as technology maturity, characteristics of incumbent technologies and price volatilities all need to be taken into consideration. In each development stage, there may be a specific trade-off between incentives being technology-neutral and closely relating to the policy drivers and on the other hand creating a sufficiently protected environment for technologies to evolve and mature.

There are two classes of currently preferred policy instruments for bio-electricity and renewable electricity in general. These are technology-specific feed-in tariffs and more generic incentives such as renewable energy quotas and tax differentiation between bioenergy and fossil-based energy. Each approach has its pros and cons, with neither being clearly more effective.

Access to markets is a critical factor for almost all bioenergy technologies, so that policies need to pay attention to grid access, and standardisation of feedstocks and biofuels.

As all bioenergy options depend on feedstock availability, a policy strategy for bioenergy should pay attention to the sectors that will provide the biomass. For the agricultural and forestry sectors, this includes consideration of aspects such as productivity improvement, availability of agricultural and forest land and access to and extractability of primary residues. For other feedstocks, such as residues from wood processing and municipal solid waste, important aspects are mobilisation and responsible use.

A long-term successful bioenergy strategy needs to take into account sustainability issues. Policies and standards safeguarding biomass sustainability are currently in rapid development. Due to the complexity of the sustainability issue, future policy making and the development of standards will need to focus on integrated approaches, in which the complex interactions with aspects such as land use, agriculture and forestry, and social development are taken into account.

Long-term continuity and predictability of policy support is also important. This does not mean that all policies need to be long-term, but policies conducive to the growth of a sector should have a duration that is clearly stated and in line with meeting certain objectives, such as cost reduction to competitive levels with conventional technologies.

The successful development of bioenergy does not only depend on specific policies which provide incentives for its uptake, but on the broader energy and environment legal and planning framework. This requires coordination amongst policies and other government actions, as well as working with industry and other stakeholders to establish a framework conducive to investment in bioenergy.

Climate change and energy security are problems for which solutions need to be developed and implemented urgently. The scale of the challenge is such that it will require contributions from disparate sources of energy. Bioenergy already contributes significantly to addressing these problems and can contribute much further through existing and new conversion technologies and feedstocks.

Furthermore, bioenergy can contribute to other environmental and social objectives, such as waste treatment and rural development. However, policy makers and the public at large will need to be comfortable that this expansion is sustainable. Bioenergy can result in many external benefits but also entails risks. A development and deployment strategy needs to be based on careful consideration of the strengths and weaknesses, as well as the opportunities and threats that characterise it.

Current bioenergy routes that generate heat and electricity from the sustainable use of residues and wastes should be strongly stimulated. These rely on commercial technologies, lead to a better use of raw materials, and result in clear GHG savings and possibly other emission reductions compared to fossil fuels. The development of infrastructure and logistics, quality standards and trading platforms will be crucial to growth and may require policy support.

Further increasing the deployment of bioenergy, and in particular of biofuels for transport in the short term, should be pursued by

- paying specific attention to sustainability issues directly related to the biomass-to energy production chain, and avoiding or mitigating negative impacts through the development and implementation of sustainability assurance schemes;
- incentivising biofuels based on their potential greenhouse gas benefits;
- considering potential impacts of biomass demand for energy applications on commodity markets and on indirect land use change;
- defining growth rates that result in feedstock demands that the sector can cope with on a sustainable basis.

Development of new and improved biomass conversion technologies will be essential for widespread deployment and long-term success. Public and private funding needs to be devoted to research, development and deployment as follows:

for liquid biofuels - advanced technologies that allow for a broader feedstock base using non-food crops with fewer (direct and indirect) environmental and social risks, and higher greenhouse gas benefits;

for power and heat production – more efficient advanced technologies, such as gasification and advanced steam cycles, and technologies with improved economics at a smaller scale to allow for more distributed use of biomass;

for novel biomass - upgrading technologies and multiproduct bio-refineries, which could contribute to the deployment and overall cost-competitiveness of bioenergy.

As the availability of residues and wastes will limit bioenergy deployment in the long term, policies stimulating increased productivity in agriculture and forestry, and public and private efforts aimed at development of novel energy crops, such as perennial lignocellulosic crops and other forms of biomass, such as algae, are essential for a sustained growth of the bio-energy industry. These efforts need to be integrated with sustainable land-use policies which also consider making efficient and environmentally sound use of marginal and degraded lands.

Acknowledgement

This paper is based on the Executive Summary of a report prepared for the IEA Bioenergy Agreement by a consortium led by the Energy Research Centre of the Netherlands (ECN), and including E4tech, Chalmers University of Technology and the Copernicus Institute of the University of Utrecht.

Bioenergy is produced from wide variety of feedstocks of biological origin and by numerous conversion technologies to produce heat, power, liquid biofuels, and gaseous biofuels. The "traditional domestic" use of fuelwood, charcoal, and agricultural residues in developing countries for household cooking, lighting and space-heating is the dominant source of world's bioenergy. The industrial use of biomass for production of pulp, paper, tobacco, pig iron, etc. produces side streams (i.e. bark, wood chips, black liquor, agricultural residues, etc.), which may be converted to bioenergy. Chemical conversion technologies (i.e. Fisher-Tropsh synthesis and other chemical routes) are used to produce liquid and gaseous fuels, and biological conversion technologies to produce biogas (i.e. anaerobic digestion) and alcohols (i.e. fermentation). In the long term, also bio-photochemical routes (i.e. algae, hydrogen, etc.) may offer new bioenergy resources.

According to the IEA Statistics, the share of bioenergy has been about 10% of Total Primary Energy Supply (TPES) since 1990 even though TPES has been increasing at an average annual rate of 2.0%. Between 1990 and 2010 bioenergy supply has increased from 38 to 52 EJ as a result of increasing energy demand in non-OECD countries and, on the other hand, new policies to increase the share of renewable and indigenous energy sources especially in many OECD and but also in non-OECD-countries. Solid biofuels, mainly wood, are the largest renewable energy source, representing 69% of world renewable energy supply. Solid biofuels are mainly used in developing countries, especially in South Asia and sub-saharan Africa. Liquid biofuels for transport provide about 4% of world renewable energy supply and 0.5% of global TPES. The share of biogases in world renewable energy supply is only 1.5% but it had the highest growth rate since 1990 (about 15% per year) compared to other biofuels. Liquid biofuels also had remarkable growth rate (11% per year) while the growth rate of solid biofuels was moderate (1% per year) (IEA 2012).

In 2010, the largest bioenergy producers were China and India, who produced 20% and 17% of the world's bioenergy respectively (IEA 2012). In China, the share of bioenergy is less than 10% of its TPES while in India it is almost 25%. In the third and fourth largest bioenergy producers, Nigeria and United States, the share of bioenergy of TPES was above 80% and below 4% respectively in 2010, which clearly shows the difference between developing and industrialized countries: in developing non-OECD countries bioenergy is typically the major energy source while in the OECD-countries bioenergy typically covers minor share of TPES.

Recently, the European Union (EU) has set binding targets to increase the share of renewables by 2020 to 20% from its energy consumption. Many non-EU countries have also set renewable targets, and bioenergy is expected to be the major contributor to reach these targets with the help of national supports schemes, like feed-in tariffs, tax incentives and investment subsidies. At the same time there is increasing concern on sustainable and reliable supply of biofuels due to its complex environmental implications and due to competition on land area between bioenergy feedstocks, food, feed, and biomaterial production. On the other hand, there is considerable potential to increase the efficiency of bioenergy production, which lies between 5% to 15% to power and heat production in the old traditional use of biomass up to 60-90% in modern applications, like combined heat and power applications, fuel cells, stirling engines, and 2nd generation biofuel concepts. Taken into account the above uncertainties, there are greatly differing estimates of the contribution of bioenergy to the TPES, from below 100 EJ/yr to above 400 EJ/yr in 2050. Unlike today, the largest bioenergy resource is expected be agricultural bioenergy resources. Sustainable forest products and wood fuel production should not cause any deforestation and thereby decrease of net carbon sinks, which limits its use. On the other hand, there are higher expectations to expand agricultural land area to produce bioenergy resources and better utilisation of agricultural residues.

Resource availability and location

Bioenergy is mainly produced from local wood resources. According to FAO statistics (2013) the world's total forest area is more than 4 billion hectares (ha), corresponding to about 30% of total land area. More than half of the world's total forest area is located in five forest-rich countries with large total land area – Russian Federation (809 million ha), Brazil (520 million ha), Canada (310 million ha), the United States (304 million ha), and China (207 million ha). In 2011, the largest woodfuel producers were India, China, Brazil, Ethiopia, and Nigeria. On the other hand, the US, Russia, and Canada were the largest producers of industrial roundwood. Both China and Brazil were included in the top five industrial roundwood producers as well.

Biofuel and bioenergy production form crops and agricultural resources has become increasingly important, as production of bioethanol and other biofuels for transportation has been promoted by several countries' energy, climate, and agricultural policies. Bioethanol production form cereals have also raised strong criticism due to concerns on its possible impacts on food security and price and due to little scope of easy expansion of agricultural land. Also, net greenhouse gas savings by crop based transportation fuels has raised concern. To limit the uncertainties related to net GHG emissions and food security, the EU has set a renewable energy directive, which calls for GHG reduction a minimum of 35% and in new plants in 2018 by 60 %.

According to the FAO Statistics (2013), about 1.5 billion ha, corresponding to about 12% of the world's land area is used for crop production (arable land plus land under permanent crops). If we also take into account permanent meadows and pastures, the total agricultural land area increases close to 5 billion ha. The accessible agricultural land is very unevenly distributed among regions and countries – about 90% is in Latin America and Sub-Saharan Africa, and there is practically no possibilities for agricultural expansion in Southern and Western Asia as well as in Northern Africa. Therefore expansion of agricultural land for producing biofuels has to take into account factors such as food supplies for increasing population, water use, biodiversity, and agro-economics, which affect the future bioenergy potentials. However, the share of agricultural land to produce biofuels is currently less than 0.01% (0,05 million ha) even though it has more than doubled since 2005 mainly due to increase of land area under oil crops, maize, as well as sugar cane and root to produce biofuels (FAO 2012). The use of sugar for biofuels is the highest (15% of total use) while the use of vegetable oils (5% of total use) and cereals (3% of total use) are still relatively low.

In the most optimistic scenarios, where bioenergy is expected to be produced annually also by photosynthesis, bioenergy meets more than the current global energy demand without competing with food production, forest product production, and biodiversity. In total, the expected contribution to the world's primary energy supply could be in the range of 250–500 EJ/yr. Based on recent literature, even with strict criteria and excluding areas with water stress or high biodiversity value, a minimum of 250 EJ/yr is likely available. The largest biomass production potential lies in large-scale energy plantations in areas with a favourable climate for maximising the production of biomass. Latin America, Sub-Saharan Africa, and Eastern Europe, along with Oceania and East and North-East Asia, have the most promises to become important producers of biofuels in the long term. However, there are still great uncertainties even with the lower range potentials, due to the impacts of climate change, speed of deforestration and erosion, and increased land use because of increased share of livestock products in protein supply, and added value of ecosystem services. Also, the technoeconomical limitations will limit the reliable and cost competitive biomass raw material supply for heat, power and transportation fuel production in future bioeconomy. On the other hand, higher improvements in biomass harvesting and logistics (both woodfuels and agrobiomass), well-functioning biofuel and food markets, increased expenditures to increase biomass yelds per ha, and changes in our habits to favour vegetarian diets and to minimize food waste could result in higher bioenergy resource potentials.

Overview of existing and emerging technologies

Traditional large scale applications on bioenergy has in most cases based on utilization and existing residues from agricultural and forest-based industries or utilization of waste streams from municipalities or industry. Another option has been replacing of a limited share or all of the use of fossil fuels with biomass in existing plants.

Choices of the technological development and implementation of new technologies are to a great extent based on existing market conditions, possible local incentives and regulations on bioenergy. Effects can be seen as different choices of feedstocks, energy carriers, capacities and technologies of energy production facilities in different countries.

Most of biomass is used locally, with limited transportation distances, but the increased use of energy carriers, such as pellets and briquettes, allow overseas transportation and replacement of fossil oil, gas and coal in many capacity scales. Variety of energy carriers from wood will increase: production of torrefied wood, fast pyrolysis oil, synthetic natural gas, and several types of transportation fuels have been demonstrated already, and several full-scale plants are planned to be demonstrated, especially in North America and European countries. Energy carriers from lignocellulosic feedstocks are typically produced by thermochemical processes, final product being solid for torrefied wood, liquid for fast pyrolysis oil or gaseous. Complexity of processes, and thus investment and operation costs depend largely on the quality specifications of final products. Highest costs are connected to products that can be mixed without blending wall to existing high-quality transportation fuels or natural gas.

Large scale heat and power production

Electricity from wood fuels is mainly produced in

- Combined heat and power (CHP) plants in municipalities and industry producing district heat, process steam and power (1-200 MWe) ,
- co-firing in large coal boilers (typically under 30% share of woodfuel),
- and medium sized electricity-only biomass power plants (1-50 MWe).

Figure 9.3

Options for large scale biomass-based heat and/or power production with variable share of biomass (20-100%) of the total fuel use in a power plant.

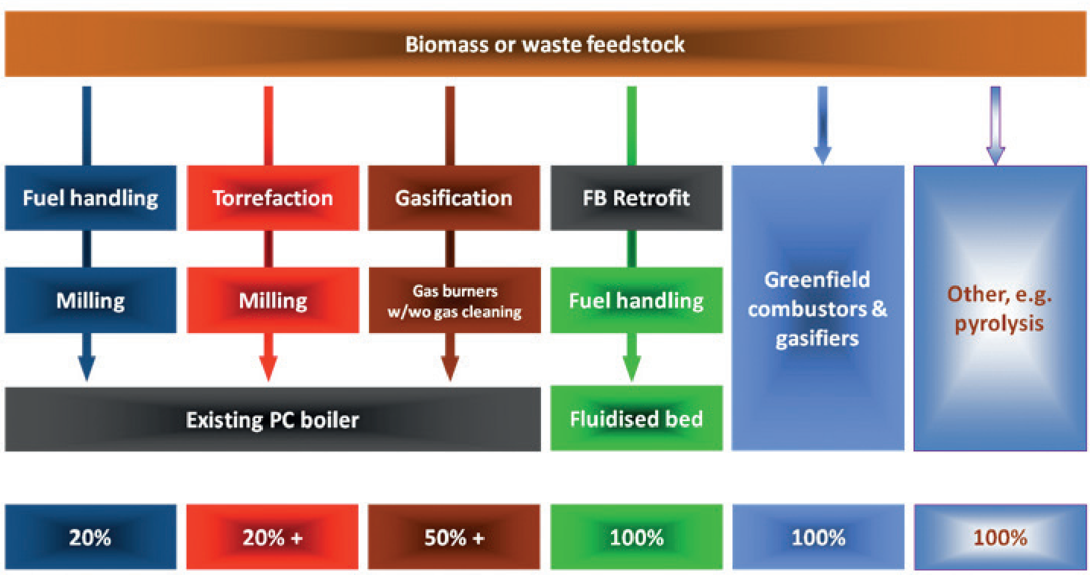
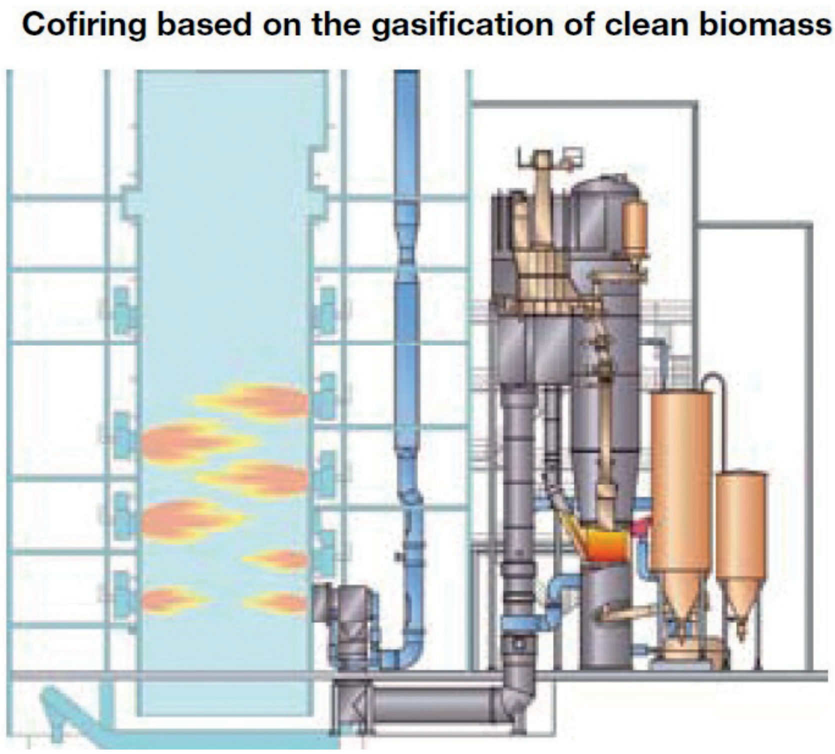


Figure 9.4
Good-quality solid recovered fuel (SRF) is gasified in the atmospheric fluidized bed gasifier and fed up to 15-20 % to the coal-fired boiler at the Kymijärvi Power Plant in Lahti, Finland.



Choice of technology and plant size depends on local conditions and quality of the fuels. Fluidized bed technology for combustion and gasification allows variable mixtures of biomass with high efficiency; also co-firing with coal is feasible. Introduction of liquid and gaseous energy carriers from solid biomass-based fuels will allow the use of high efficiency technologies, such as combustion engines, combined cycle plants, and fuel cells, and use of biomass for small-scale power production replacing fossil fuels.

Transition to low carbon economies requires 80-95% reduction in greenhouse gas emissions (GHG), which means that CO2 emissions form energy production, should be close to zero, or even negative. Capturing CO2 of biogenic origin from flue and process gases results in negative net emissions, which could offer cost-effective solutions for GHG emission reductions. This bio-CCS (carbon capture and storage) could be an option both in large scale co-firing and biomass-only plants as well as in pulp and paper industries, when the value of avoided CO2 emission is high, in the level of 100 €/t

Transportation fuels
The main transport biofuels on the market today are bioethanol, different fatty acid methyl (or ethyl) esters (biodiesel), and to a lesser extent also methane (biogas). Bioethanol has, by far, the largest market.

The main two technologies of advanced biofuels are producing biofuels from solid biomass by a so-called gasification route or sugar route. In the first process type, biomass is first gasified, the gasification product gas is cleaned and processed to form a synthesis gas, which is then used in a commercial chemical synthesis process to produce liquid biofuels like Fischer-Tropsch diesel, methanol, ethanol, MTBE/ETBE, dimethylether (DME) or gaseous biofuels like methane or hydrogen. Ethanol can be produced by biotechnical processes based on hydrolysis of lignocellulosic raw materials and fermentation of the extracted sugars.

Hydrogenation of oils and fats is a process that has entered in the market very fast with high volumes. In the process vegetable oils and animal fats are converted to renewable diesel fuel. The produced synthetic diesel fuels can be used as a blending component or as such.

Next generation biofuels can be used without blending wall in existing and future power trains. Fuel consumption will be lowered with dedicated tail pipe cleaning requirements. Ethanol can be used up to E85 blends and modern paraffinic bio diesel can be used up to 100 % in current engines. In a short perspective, hybrid vehicles are often considered as the most promising alternative vehicle technology. Advantage of this technology is the possibility to save fuel by smoothing out the operation of the internal combustion engine and by recovering braking energy. Compared to other alternative vehicle technologies, the hybrid technology provides possibilities to reduce energy consumption and exhaust emissions without the need for a new infrastructure. This is why these vehicles are often seen a step towards plug in hybrid vehicles, fuel cell vehicles and a full electric propulsion.

Environmental implications

Bioenergy production can have various and complex environmental impacts which can be positive or negative depending on the biomass type used for bioenergy production, local conditions, intensity and efficiency of biomass use, and the auxiliary inputs used in bioenergy production. The impacts can occur in a local or global scale, and can be classified as direct or indirect. The positive environmental impacts of bioenergy production are often considered to be the renewability of the raw material used and its carbon neutrality over the biomass growth cycle. The main environmental challenges due to intensified bioenergy production are mostly related to the feedstock production, such as impacts on land use, soil carbon and nutrient stocks, biodiversity, and on water use. Also the end use of bioenergy can have negative environmental impacts, especially in the developing countries, where traditional open fires and low-efficiency stoves produce large amounts of incomplete combustion products with negative consequences for climate change and local air pollution (Chum et al. 2011). Furthermore, the foreseen climate warming can have significant but currently uncertain effects to biomass production and its sustainability.

The effects on land use occur due to competition on land area between bioenergy feedstocks, food, feed, and biomaterial production. The indirect land use change (iLUC) occurs, when the cultivation of bioenergy raw material forces for example food production to other locations with land use impacts. The iLUC impacts are generally related to the oil crops and to other agricultural feedstocks, and can significantly reduce the greenhouse gas (GHG) emission reduction potential of the bioenergy products (e.g. Searchinger et al. 2008). Another environmental impact related to agricultural feedstocks is the water use, which can be a critical issue for water intensive crops and for locations with water shortage. Impacts on biodiversity and soil resources and habitat loss can occur due to intensified agro- or forest bioenergy production (Chum et al. 2011). Currently, a widely discussed issue related to the forest bioenergy is the carbon and climate neutrality of forest biomass (Cherubini et al. 2011; Helin et al. 2012). Bioenergy can be considered as carbon neutral, if the carbon emitted in biomass combustion is re-absorbed to the re-growing biomass. However, bioenergy might not be climate neutral, if the period for re-absorption of carbon is very long (e.g. 80 years for Boreal forests), as the carbon released in the combustion has a warming impact during its stay in the atmosphere (Cherubini et al. 2011). If the climate impacts are studied for a shorter period of time due to tight schedule for the needed emission reductions (e.g. 20-30 year), forest biomass may not be considered carbon neutral, nor climate neutral over this time scale. Generally, the environmental impacts are considered to be less relevant for bioenergy systems using waste and residue materials as input, as they do not compete on land and other auxiliary resources. However, intensified use of residues can have an effect on soil carbon and nutrient stocks. Currently, also the waste hierarchy, and the definitions of which type of materials can be defined as wastes or residues are discussed. Recently, also a question on whether and how efficiently bioenergy replaces fossil fuels has been raised, affecting the emission reduction potential of bioenergy (Rajagopal et al. 2011; York 2012). There are still many uncertainties related to the lifecycle-GHG emission assessments of bioenergy, which should be studied by the scientific communities in coming years.

There are several initiatives established in order to evaluate and control the environmental sustainability of bioenergy products, most of which are specified on the production of liquid biofuels for transportation. For example, the European Union (EU) has established the environmental sustainability criteria for liquid biofuels and other bioliquids in its Renewable Energy Directive (RED, 2009/28/EC) (EU 2009). A biofuel product must comply with these criteria, in order to be accounted to national targets for renewable energy and to benefit from subsidies. The RED sets the emission saving limits that biofuels have to gain compared to fossil fuels (first 35 % and later 60% emission reduction), and introduces a first-ever life cycle analysis (LCA) based mandate methodology to calculate the GHG emission balances of biofuels and other bioliquids. EU is also planning to take the iLUC impacts into consideration in the RED sustainability criteria (EC 2012). A strong incentive is given for the use of waste and residues, as biofuels produced from these raw materials can be counted as double towards the national targets for renewable energy in transportation (EU 2009). European Commission has also accepted some voluntary schemes, such as ISCC, RED Cert and Biograce GHG calculation tool to be suitable for GHG assessment according to the RED (EC 2013). EU is planning to establish similar criteria for bioenergy from solid and gaseous biomass (EC 2010).

Also in the USA sustainability criteria have been established for biofuels, such as the Renewable fuel standard in the USA, included in the 2007 Energy Independence and Security Act (EISA 2007), and the Low carbon fuel standard in California (CARB 2009). The Renewable Fuel Standard demands for minimum GHG reductions from renewable fuels, discourages use of food and fodder crops as feedstocks, and estimates the (i)LUC effects. The California Low Carbon Fuel Standard sets an absolute carbon intensity reduction standard for biofuels, and demands for periodical evaluation of new information, e.g. on iLUC impacts (Chum et al. 2011).There are also several voluntary schemes to evaluate the sustainability of specific bioenergy feedstocks (e.g. Roundtable on Sustainable Palm Oil, and Round Table on Responsible Soy EU RED, Better Sugarcane Initiative) (EC 2013; Chum et al. 2011).

Bioenergy markets

Global trade in biomass feedstocks (e.g. wood chips, vegetable oils and agricultural residues) and processed bioenergy carriers (e.g. ethanol, biodiesel, wood pellets) is growing rapidly boosted by national policies, like feed-in tariffs, in some European countries. Present estimates indicate that bioenergy trade is modest – around 1.1 EJ (about 2% of current bioenergy use even though the volume of energy biomass trade has been increasing. Especially the direct trade of biofuels has grown rapidly but the indirect trade through the trading of industrial roundwood and material by-products has been relatively stable over the past years. The global economic recession caused the indirect trade to decrease between 2008 and 2009; a time span during which the direct trade continued to grow. The importance of the direct trade has increased remarkably. In 2004, the direct trade covered less than a fourth of the total global bioenergy trade. In 2011, the proportion of direct trade had increased to 45%.

The international trade of biomass and biofuels for energy production is much smaller than the international trade of biomass for other industrial purposes. Most of the biomass products are mainly consumed locally in the countries of production, but in the case of products such as sawn timber, paper and paperboard, palm oil, and wood pellets, a considerable proportion of the total production is exported.

Table 1 gives an estimate of the scope of international trade of biomass for energy purposes in 2004–2011. In the case of ethanol and palm oil (and other vegetable oils), the final use is not always clear, and some assumptions had to be made, as to how much of the total trade is earmarked for fuel use. The figures in Table 1 should therefore be considered as indicative showing the scales of various energy biomass trade streams.

Table 1

Estimated scope of international biomass fuel trade between 2004 – 2011 in PJ (excluding tall oil, ETBE, and waste)

Source: Heinimö et al 2013

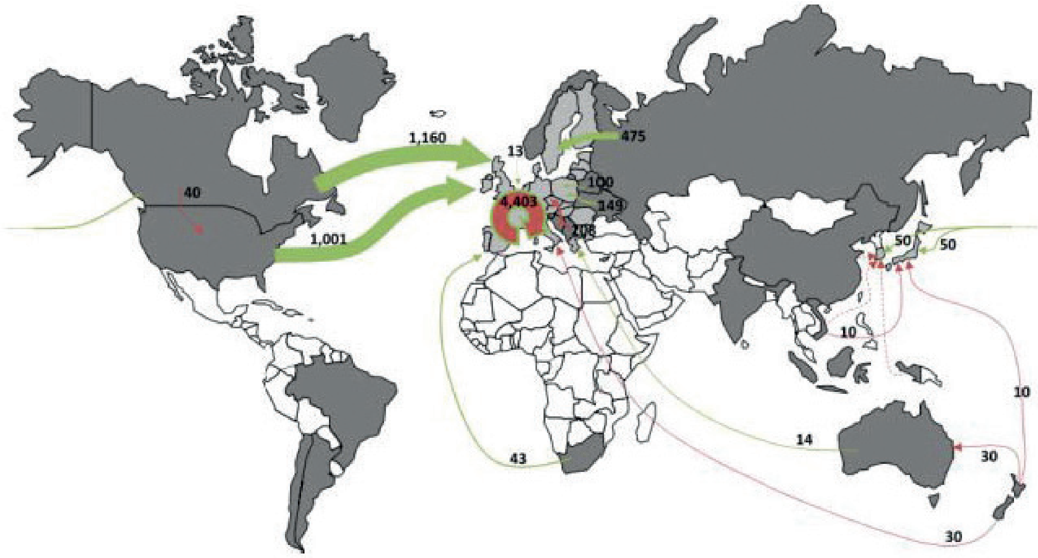
Year/product	2004	2005	2006	2007	2008	2009	2010	2011
Indirect trade	585	640	636	671	606	493	598	648
industrial roundwood	450	488	488	507	431	341	404	444
wood chips and particles	136	152	149	165	175	152	194	204
Direct trade	203	230	292	337	467	449	438	500
Charcoal	27	31	35		38	39	44	46
Fuel wood	33	35	39	38	38	51	51	60
Wood pellets	26	42	55	50	53	84	120	135
Biodiesel	0	2	4	33	89	83	97	112
Ethanol	91	85	120	126	178	122	60	69
Palm oil (and other vegetable oils for biodiesel)	26	34	39	56	71	70	66	78
Total	**788**	**870**	**929**	**1 009**	**1 072**	**942**	**1 036**	**1 148**

Trade in *wood chips for energy* (virgin and/or tertiary residues) is practically limited to Europe, Turkey, and Japan, being less than 20 PJ annually. The direct trade of wood chips for energy purposes is thus about 10% of the indirectly traded volume (in terms of calorific value).

Apart from heating and cooking (including barbeque in industrial countries), *charcoal* is applied in the chemical (as active coal) and in the iron and steel industry (as a reducing agent and energy source). The largest producer between 2000 and 2010 was Brazil (13%), where most charcoal is used in pig iron production. The international trade with charcoal has been dominated by Germany (10%), Japan (9%), and South Korea (8%) in terms of imports. Total world exports have been led by Somalia over the past four years. Up to now there has been no direct and large scale trade for modern energy conversion, and the current trade for energy purposes is limited to heating, cooking, and barbeque. During 2004–2011, the charcoal trade volumes have almost doubled.

Fuel wood use for heat generation in high performance boilers and stoves has been heavily driven across the EU over the last years. Its share in the global trade increased from 50% (2000–2004) to over 80% (2007–2011). Most of this trade is cross-border trade: short- or mid-range in bagged form, conglomerated in nets, or stacked on pallets. Recorded trade

Figure 9.5
Major global wood pellet trade streams in 2011 (in kilotonnes).
Source: Heinimö et al 2013.



streams outside Europe are between South Africa and its neighbouring countries (Swaziland and Namibia), Canada and the USA, and across South East Asia. By 2010, half of the total fuel wood production was centred in India (17%), China (10%), Brazil (8%), Ethiopia (5%), Congo (4%), Nigeria (3%), and Indonesia (3%) [15]. Similarly to the charcoal trade, the volumes of fuel wood had almost doubled compared to the figures of 2004.

Wood pellets have become one of the most important energy biomass commodity. International trade volumes of pellets have constantly been increasing since 2004: the trade has increased fivefold from 2004 to 2010. Around 60% of the global wood pellet production was concentrated in the EU, Figure 9.5. Since 2000, EU production, demand, and imports have increased more than tenfold [7]. Until 2010, most pellets were combusted in residential heating (dominated by Italy, Germany, and Austria), followed by district heating (Sweden and Denmark), and large scale power production (concentrated in Belgium, the Netherlands, and the UK). While being relatively self-sufficient in the residential pellet market segment, the EU has become heavily import-dependent in the industrial pellet market. This is largely due to the strong increase in demand (predominantly from the Netherlands and the UK), but also linked to a limited mobilisation and production (within the EU and its border countries), competitive to overseas pellet export prices. In 2009, approximately 1.7 Mtonnes were imported from outside the EU. By 2012, this volume had risen to 4.6 Mtonnes, Figure 9.5). By 2020, EU wood pellet imports are expected to be in the range of 15–30 Mtonnes. While the majority of this volume will be industrial pellets, wood pellet imports for the domestic market are also expected to increase.

To overcome barriers in biomass and biofuel trade for energy, technical standards are a perquisite to allow for commoditisation of biomass and biofuels. ISO is currently preparing almost 60 standards for solid biofuels. Pellet standards under development will specify general requirements, graded pellets and non-woody graded pellets, and quality for industrial pellets. ISO standards under development also consist of classification of raw material, which is based on their origin and source, and specifications for woody biomass, herbaceous biomass, fruit biomass, aquatic biomass, blends and mixtures, and thermally treated biomass (e.g. torrefied biomass)(see Alakangas 2013). Threshold values for new standards have been agreed, and they will be published in 2014.

Figure 9.6
Example of an A-frame silo for the large-scale storage of solid biofuel.
Source: Raumaster

Lessons learnt and key actions for the future

Several scenario studies for the transition low carbon society by 2050 has indicated that globally the transport and industrial sectors are the most challenging sectors to decarbonize. Both of these sectors could replace the use of fossil fuels by biofuels to a certain extent, but the limiting factor would be the availability and price of sustainable biofuels. In addition, the role of biomass as a resource for material use is increasing as new processes and products are being developed in chemical and other industries in future bioeconomy. Therefore it is important to use bioenergy resources on those sectors, where the special properties of biomass may be utilized, and on the other hand, where the deepest, cost effective greenhouse gas emissions reductions may best achieved. As an example, heavy road transport and aviation could hardly be decarbonized without biofuels.

As a storable form of renewable energy, biofuels will have a vital role in hybrid renewable energy solutions in future low carbon energy systems. Recently, the investments on variable wind and solar power have increased the need for balancing power and energy storages. In those countries, where natural gas infrastructures and gas storages already exist, synthetic methane (SME) and biogas may offer cost-effective solution to balance electricity supply and demand. Liquid biofuels may replace mineral oils to produce peak power and heat, and on the other hand, solid biofuels could replace coal and other solid fossil fuels as a balancing energy source during seasonal high energy demands and/or low renewable energy production.

As current energy systems are largely based on fossil fuels, hybrid systems offer short term solutions to increase the share of bioenergy of TPES. The hybrid systems are cost-effective solutions in many countries already today, even though market prices of both fossil fuels and emissions allowances have experienced downward trend. Advanced new combustion technologies, like multifuel fired fluidized bed combustion, allow for using wide range of renewable wastes and other low grade renewable materials for energy production, and investing in new high efficiency technologies offer better cost-efficiency and reduced environmental impacts, both direct and indirect.

In the long term, transition to "bioeconomy" could offer pathway for a low carbon society, where the basic building blocks for industry and the raw materials for energy are derived from plant or crop-based sources as well as from municipal and livestock wastes. Today, it is not known, which new technologies and new products will emerge into the markets, and which bio-based products (i.e. energy, transport fuels, or industrial products) will have the best paying ability against competing energy technologies, fuels, or industrial products. For example, the IEA Roadmaps for transport and biofuels (IEA 2011) and for heat and power (IEA 2012b) expect that biofuels could provide up to 65 EJ transport fuels and additional 80 EJ for electricity and heat. Producing such amount of biofuels requires around 170-300 million ha land area in 2050, which is about 4-6% of existing agricultural land area (IEA 2012). For comparison, it is estimated that by 2050 global agricultural production will have to increase by 60% from its 2005-2007 level to feed the increasing population, which will require expansion of arable land by about 70 million ha (FAO 2013).

The way forward

The bioenergy success stories in industrialized countries with the highest share of bioenergy of their TEPS has usually based on the sustainable use of local residues and resources and long-term policy framework to support RD&D of the whole bioenergy value chain to develop and deploy high efficiency bioenergy technologies and to ensure reliable and low cost fuel supply. In addition, national energy, climate, employment, education, agriculture, and/or forestry policies have promoted bioenergy in many ways in these countries.

Today's cost-effective bioenergy concepts use often renewable biogenic waste or industrial side streams, like black liquor, agricultural and municipal solid wastes, to produce combined heat and power or heat for industries and communities. Co-firing of bioenergy feedstock with fossil fuels is also a cost-effective solution in many applications. In addition, the lowest life-cycle GHG emissions can be achieved through use of residues and wastes on site.

It can be expected that the traditional use of woodfuel will have a major role in the future small scale applications as well. Therefore it is important to develop technologies and catalyse investments in new, more efficient biomass stoves in developing countries to increase the energy efficiency and to decrease environmental impacts.

Due to limited availability of sustainable biomass resources, biofuels and biomaterials should be used in those sectors, which have limited options for deep greenhouse gas emission reduction (i.e. transport and process industries), which have high cost-effectiveness (i.e. usage as balancing power and energy storage), and where the special properties of biomass may be utilized (i.e. new bio-based products which cannot be produced from mineral oil).

One of the most viable sectors for bioenergy is transport sector, where the share of biofuels should be increased from the current 3% to above 25% by 2050. To reach this target, advanced 2nd generation biofuel technologies should be commercially deployed. The current use of cereals based transportation biofuels have clear blending wall like E10 or B7, which must have complimentary solutions by next generation dropping ("no blending wall") biofuels produced form sustainable cellulosic resources, as much as possible.

The deployment of maximum sustainable bioenergy potential will require well-functioning markets for biofuels, food and other bio-products, to ensure both food security and reliable biofuel supply. Development of biofuel markets requires also internationally agreed sustainability criteria and certification schemes to abolish trade barriers, now and in the future.

Development of novel biomass conversion technologies and integrated concepts as well as new bioenergy resources, like algae-based biofuels, could offer new solutions for increased use of bioenergy. Investments on bio-CCS could also offer cost effective solution for achieving low carbon societies, but the implementation requires new policies to take into account "net negative emissions".

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Country notes

Argentina

Biodiesel produced in 2011, tonnes	2 376.297
Biodiesel production capacity in 2011, tonnes per year	3 100
Ethanol produced in 2011, tonnes	131 389

Austria

Electricity: installed capacity in 2011, MW	300
Electricity: actual generation in 2011, TJ	11 500
Ethanol production, installed capacity in 2011, TJ/year	5 000
Ethanol energy produced in 2011, TJ	2 210
Biodiesel installed capacity in 2011, TJ/year	17 000
Biodiesel energy produced in 2011, TJ	6 618

Brazil

Electricity: installed capacity in 2011, MW	1 178 869
Electricity: actual generation in 2011, TJ	25 913
Ethanol installed capacity in 2011, TJ/year	572 477
Ethanol production in 2011, TJ	358 025
Biodiesel installed capacity in 2011, TJ/year	213 666
Biodiesel production in 2011, TJ	78 710

Canada

Ethanol installed capacity in 2011, TJ	41 906
Ethanol production in 2011, TJ	40 060

Croatia

Electricity: installed capacity in 2011, MW	6 500
Electricity: actual generation in 2011, TJ	128.53
Biodiesel installed capacity in 2011, TJ/year	2 361.6
Biodiesel production in 2011, TJ	283
Biogas installed capacity in 2011, TJ/year	423.45
Biogas production in 2011, TJ	128.53

Czech Republic

Ethanol installed capacity in 2011, TJ/year	4 320
Ethanol production in 2011, TJ	1 469
Biodiesel installed capacity in 2011, TJ/year	15 540
Biodiesel production in 2011, TJ	7 773

Estonia

Electricity: installed capacity in 2011, MW	120
Electricity actual generation in 2011, TJ	2 664

Finland

Solid fuel production installed capacity in 2011, TJ/year	12 600
Solid fuel production in 2011, TJ	3 200
Ethanol installed capacity in 2011, TJ/year	293
Ethanol production in 2011, TJ	210
Biodiesel installed capacity in 2011, TJ/year	15 910
Biodiesel production in 2011, TJ	12 100
Biogas installed capacity in 2011, TJ/year	2156.5
Biogas production in 2011, TJ	53

Germany

Electricity installed capacity in 2011, MW	3 099
Electricity production in 2011, TJ	68 040
Ethanol installed capacity in 2011, TJ/year	24 680
Ethanol production in 2011, tonnes	577 000
Biodiesel installed capacity in 2011, TJ/year	177 930
Biodiesel production in 2011, tonnes	2 870 000

Italy

Electricity installed capapcity in 2011, MW	2 824
Electricity actual generation in 2011, TJ	38 996.64
Biodiesel installed capacity in 2011, tonnes/year	2 395 240
Biodiesel production in 2011, tonnes	620 000

Japan

Electricity installed capacity in 2011, MW	319
Electricity actual generation in 2011, TJ	15 128

Latvia

Electricity installed capacity in 2011, MW	12
Electricity actual generation in 2011, TJ	400

Mexico

Electricity installed capacity in 2011, MW	89.9
Electricity actual generation in 2011, TJ	49 199
Solid fuel production installed capacity in 2011, TJ/year	47 929.76
Solid fuel production energy produced in 2011	47 929.76
Biodiesel installed capacity in 2011, TJ/year	1 470
Biodiesel production in 2011, TJ	1 470
Biogas installed capacity in 2011, TJ/year	1 470
Biogas production in 2011, TJ	1 470

Romania

Electricity installed capacity in 2011, MW	25
Electricity actual generation in 2011, TJ	659

Serbia

Biodiesel installed capacity in 2011, TJ/year	4
Biodiesel production in 2011, TJ	2 400

Sweden

Electricity installed capacity in 2011, MW	2.9
Electricity actual production in 2011, TJ	43 920

Switzerland

Solid fuel production installed capapcity in 2011, MW	10 584
Solid fuel production in 2011, TJ	39 206

7b

Waste to Energy

Contents

Strategic insight

1. Introduction and Global Status

Waste-to-Energy (WtE) technologies consist of any waste treatment process that creates energy in the form of electricity, heat or transport fuels (e.g. diesel) from a waste source.

These technologies can be applied to several types of waste: from the semi-solid (e.g. thickened sludge from effluent treatment plants) to liquid (e.g. domestic sewage) and gaseous (e.g. refinery gases) waste. However, the most common application by far is processing the Municipal Solid Waste (MSW) (Eurostat, 2013). The current most known WtE technology for MSW processing is incineration in a combined heat and power (CHP) plant.

MSW generation rates are influenced by economic development, the degree of industrialisation, public habits, and local climate. As a general trend, the higher the economic development, the higher the amount of MSW generated. Nowadays more than 50% of the entire world's population lives in urban areas. The high rate of population growth, the rapid pace of the global urbanisation and the economic expansion of developing countries are leading to increased and accelerating rates of municipal solid waste production (World Bank, 2012). With proper MSW management and the right control of its polluting effects on the environment and climate change, municipal solid waste has the opportunity to become a precious resource and fuel for the urban sustainable energy mix of tomorrow: only between 2011 and 2012, the increase of venture capital and private equity business investment in the sector of waste-to-energy - together with biomass - has registered an increase of 186%, summing up to a total investment of USD 1 billion (UNEP/Bloomberg NEF, 2012). Moreover, waste could represent an attractive investment since MSW is a fuel received at a gate fee, contrary to other fuels used for energy generation, thus representing a negative price for the WtE plant operators (Energy Styrelsen, 2012).

However, an increasingly demanding set of environmental, economic and technical factors represents a challenge to the development of these technologies. In fact, although WtE technologies using MSW as feed are nowadays well developed, the inconsistency of the composition of MSW, the complexity of the design of the treatment facilities, and the air-polluting emissions still represent open issues for this technology.

The development of WtE projects requires a combination of efforts from several different perspectives. Along with future technical developments, including the introduction in the market of alternative processes to incineration, it is nowadays crucial to take into account all the social, economic and environmental issues that may occur in the decision making process of this technology.

Growing population, increased urbanization rates and economic growth are dramatically changing the landscape of domestic solid waste in terms of generation rates, waste composition and treatment technologies. A recent study by the World Bank (2012) estimates that the global MSW generation is approximately 1.3 billion tonnes per year or an average of 1.2 kg/capita/day. It is to be noted however that the per capita waste generation rates would differ across countries and cities depending on the level of urbanization and economic wealth.

Figure 1

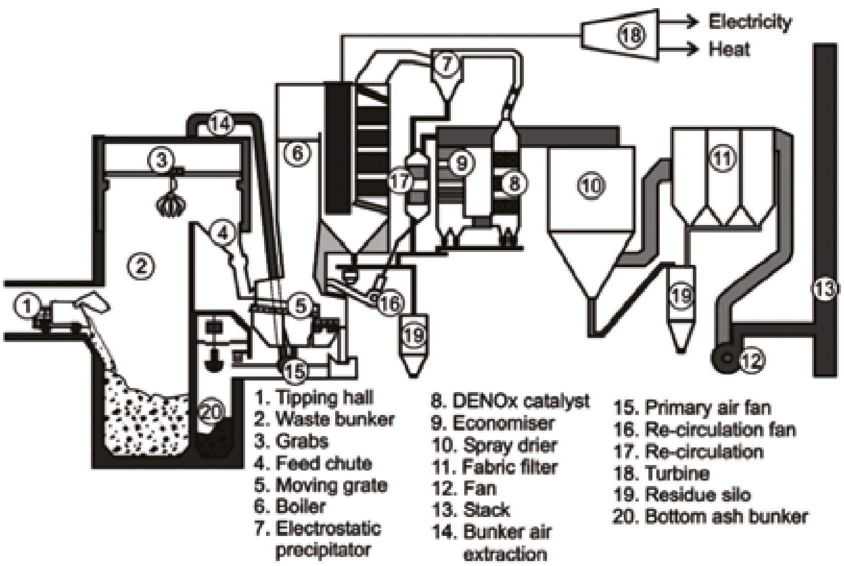


Figure 2

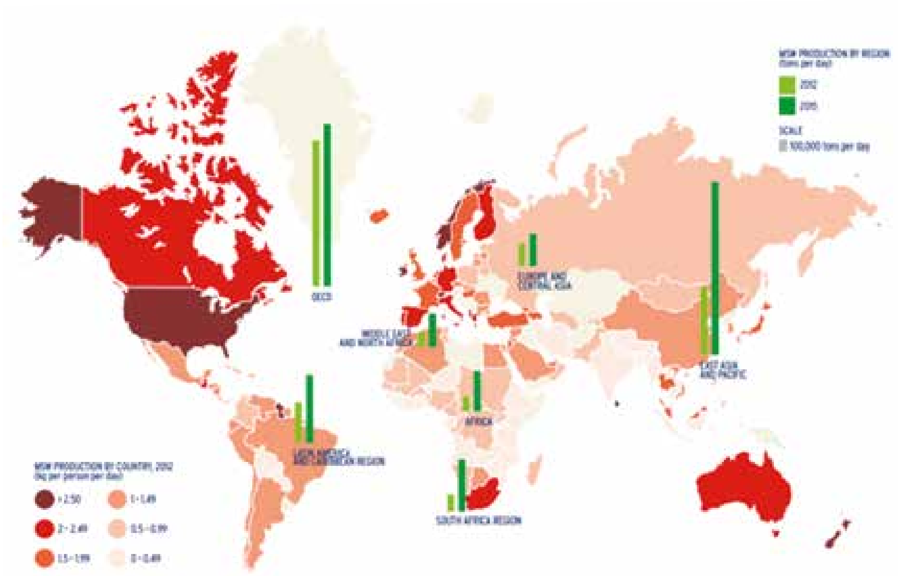
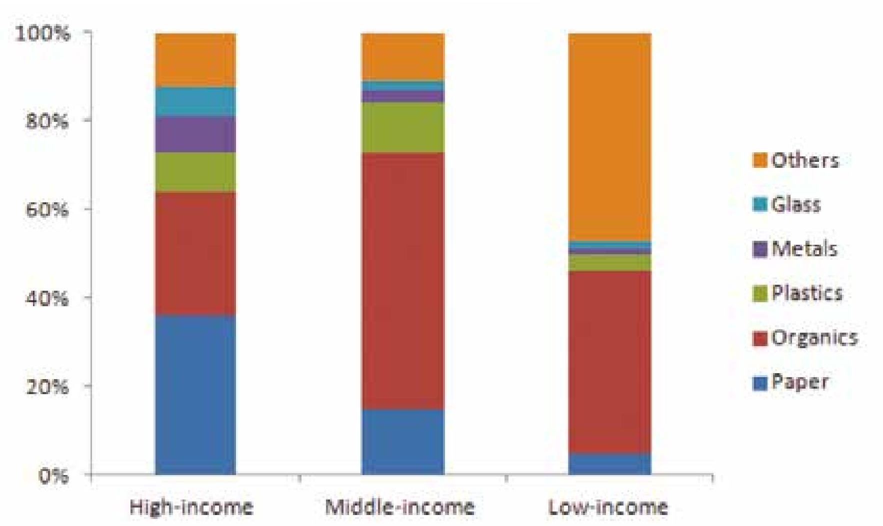


Figure 3



The amount of municipal solid waste generated is expected to grow faster than urbanization rates in the coming decades, reaching 2.2 billion tons/year by 2025 and 4.2 billion by 2050 (World Bank, 2012; Mavropoulos, 2012).

Today, the majority of MSW is generated in developed countries (North America and European Union) as shown in Figure 2. However, the fastest growth in MSW generation for the coming decade is expected mainly in emerging economies in Asia, Latin America and South Africa.

In terms of waste composition, there is a shift towards an increased percentage of plastic and paper in the overall waste composition mainly in the high-income countries, as shown in Figure 3 (UNEP, 2010). It is expected that both middle- and low-income countries would follow the same trends with the increase of urbanization levels and economic development in these countries.

2. Technical and economic considerations

WtE technologies are able to convert the energy content of different types of waste into various forms of valuable energy. Power can be produced and distributed through local and national grid systems. Heat can be generated both at high and low temperatures and then distributed for district heating purposes or utilized for specific thermodynamic processes. Several types of biofuels can be extracted from the organic fractions of waste, in order to be then refined and sold on the market.

As of today, the most common and well-developed technology is in the form of Combined Heat and Power plants, which treat Municipal Solid Waste - and possibly a combination of industrial, clinical and hazardous waste, depending on the system settings - through an incineration process. Technical and economic considerations will be therefore limited to this type of plant.

By definition, waste incineration is carried out with surplus of air. This process releases energy and produces solid residues as well as a flue gas emitted into the atmosphere (Hulgaard T. & Vehlow J., 2011). Because of emission and safety concerns, there is a certain temperature range that is demanded for this type of process. In the case of mixed waste, a furnace temperature of 1050°C is required. A generic description of an incineration process is represented in the following figure (Figure 1). As depicted in Figure 1, waste is first deposited and then extracted from a bunker, and then it is processed on a moving grate in order to achieve a correct combustion. Before undergoing the combustion phase, the incoming waste may be exposed to pretreatment, depending on its quality, composition and the selected incineration system.

The combustion products (flue gases) then exchange heat in a boiler, in order to supply energy to a Rankine cycle. This cycle will then provide power and heat by activation of a turbine and by means of a heat exchanger respectively. The choice of the boiler type is strictly related to the choice of the desired final use of the produced energy.

Within the incineration plant, the flue gas cleaning system (which can be designed in different ways - from filters to electrostatic precipitators) and a series of fans ensure both a correct combustion process and controlled emissions. However, there will be a certain percentage of substances emitted into the atmosphere, depending on the MSW composition and on the type of cleaning systems used. The common pollutant particles in the flue gas are CO_2, N_2O, NO_x, SO_x and NH_3.

Furthermore, it is possible to achieve energy recovery within the cleaning system, when focusing on the flue gas flow. Apart from flue gases that are used to produce heat and power in the incineration plant, the other main product of the process consists of solid residues, mostly in the form of bottom ash or slag and fly ash; some of which can be reused in applications such as filling in the building and construction industries.

The efficiencies for the described incineration process, in terms of energy production, are typically around 20-25% if operating in CHP mode and up to 25-35% in the case of power production only. The size of CHP plants can vary significantly, both in terms of waste input capacity and of power output. A typical capacity is of one (or few) process units, each one dealing with 35 tonnes/hr of waste input (Energinet, 2012). According to the Energy Styrelsen report about Technology Data for Energy Plants (2012), the best example of available WtE incineration technology is the Afval Energie Bedrijf CHP plant in Amsterdam, in operation since 2007. It is the largest incineration plant in the world (114.2 MW) and is able to process 1.5 million tonnes of MSW per year with an electricity generation efficiency of 30%.

It is typical for the described technology to be running at full load during all operation hours, and therefore to be utilized as a base load unit within the electricity generation mix. However, especially in new plant designs, it is possible to achieve significant flexibility of operations through down-regulation, without exceeding the fixed limits for steam quality and environmental performance.

The most important economic difference between WtE technologies and other combustion-based energy generation units is strictly related to the nature of the input fuel. Waste has a negative price, which is regulated by prefixed gate-fees, and is usually considered as the main source of income for the WtE plant owners. In this sense, incineration facilities have the primary purpose of waste treatment. Generation of electricity and heat can be considered as a useful byproduct, with relative additional earnings. Furthermore, the dispatch of power from WtE units is prioritized over other generation units, thus yielding a guaranteed income form during all operations.

Regarding the technology-related costs, the initial investment costs for the construction of the plant play an important role because of the large size of these facilities and of the main installed components. Capital costs, however, can vary significantly as a function of the selected processes for the treatment of flue gases and other produced residues. Operation and maintenance costs have a lower impact on the total expenses of the facility and are mainly related to the amount of treated waste.

3. Market trends and outlook

Despite the recent economic crisis, the global market of waste to energy has registered a significant increase in the past few years and is expected to continue its steady growth till 2015. In 2012, the global market for waste-to-energy technologies was valued at USD 24 billion, an average annual increase of 5% from 2008. The waste to energy market is expected to reach a market size of USD 29 billion by 2015 at a Compounded Annual Growth Rate (CAGR) of 5.5% (Frost & Sullivan, 2011).

The main drivers for this growth could be summarized in an increasing waste generation, high energy costs, growing concerns of environmental issues, and restricted landfilling capacities. WtE would help solve these issues by reducing the waste volume and cutting down on greenhouse gas emissions. Moreover, legislative and policy shifts, mainly by European governments, have significantly affected the growth of WtE market as well as the implementation of advanced technology solutions.

Figure 4.1

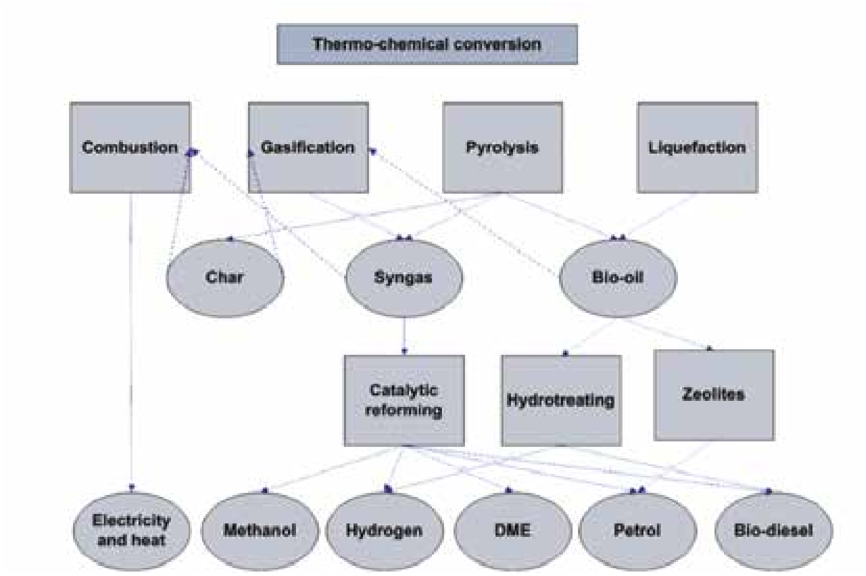
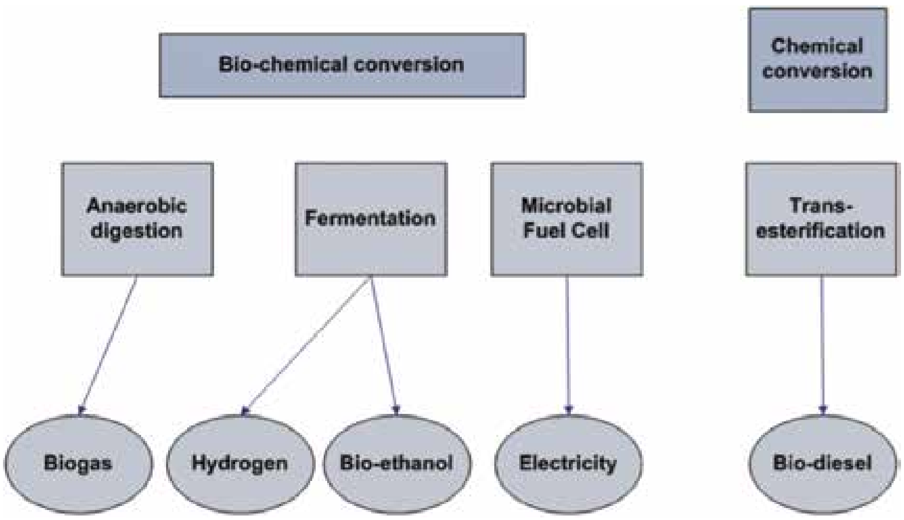


Figure 4.2



The thermal WtE segment is expected to keep the largest share of the total market (approximately 90% of total WTE revenues by 2015). This segment would be expected to increase from 18.5 to reach USD 25.3 billion by 2015 at a CAGR of 6.7%. The biochemical WtE segment would witness a rapid growth from USD 1.4 billion to USD 2.75 billion in 2015 at a CAGR of 9.7% (Frost & Sullivan, 2011).

In terms of markets, the Asia-Pacific region is the fastest growing market for WtE and should witness a significant growth by 2015 with major expansions in China and India. Many of these countries see WtE as a sustainable alternative to landfills. The European market is expected to expand at an exponential rate for the next decade with European Union's efforts to replace the existing landfills with WtE facilities. Moreover, there is a current trend with the private sector actively developing large-scale WtE projects as opposed to the traditional public sector monopoly. This would influence the future of WtE as more players would be expected to enter the market which would help decrease prices and increase technological advancements.

Currently, CHP incineration is the most developed and commercialized technology for WtE conversion. However, a number of different technological configurations are already available for this purpose and, with a constant R&D, many others are envisioned to become valuable alternatives in the future.

The following classification illustrates the possible methodologies which can be used in order to obtain energy from waste.

Thermo-chemical conversion

Looking at thermo-chemical conversion processes, in which the energy content of waste is extracted and utilized by performing thermal treatments with high temperatures, the choice of fuel strongly determines the type of process.

- **Incineration:** With mixed waste input, simple incineration is often utilized by means of the previously described CHP plant technology.
- **Co-combustion:** Co-combustion with another fuel (typically coal or biomass) is an alternative that makes it easier to control the thermal properties of the fuel; in particular the Lower Heating Value. Also, co-combustion is an attractive alternative to simple coal combustion both in terms of costs and emission levels (Rechberger H., 2011).
- **Residual Derived Fuel (RDF) Plant:** The possibility to achieve higher energy contents is the main advantage of Refuse-Derived Fuel (RDF), which can be achieved from different kinds of waste fractions. Its high and uniform energy content makes it attractive for energy production, both by mono-combustion and co-combustion with MSW or coal (Rotter S., 2011).
- **Thermal Gasification:** Thermal gasification is a process which is able to convert carbonaceous materials into an energy-rich gas. When it comes to gasification of waste fractions, it is often agreed that this technology is not yet sufficiently developed in comparison to combustion. However, this process could present many favorable characteristics such as an overall higher efficiency, better quality of gaseous outputs and of solid residues and potentially lower facility costs (Astrup T., 2011). Thus gasification, with proper future technology developments, could be considered a valuable alternative to combustion of waste.

Bio-chemical conversion

Energy can also be extracted from waste by utilizing bio-chemical processes. The energy content of the primary source can be converted, through bio-decomposition of waste, into energy-rich fuels which can be utilized for different purposes.

- **Bio-ethanol production:** Bio-ethanol can be produced by treating a certain range of organic fractions of waste. Different technologies exist; each of which involving separate stages for hydrolysis (by enzymatic treatment), fermentation (by use of microorganisms) and distillation. Other than bioethanol, it is possible to obtain hydrogen from the use of these technologies, which is a very useful and promising energy carrier (Karakashev D. & Angelidaki I., 2011)
- **Dark fermentation and Photo-fermentation producing bio-hydrogen:** Dark fermentation and photo-fermentation are techniques that can convert organic substrates into hydrogen with the absence or presence of light, respectively. This is possible because of the processing activity of diverse groups of bacteria. These technologies can be interesting when it comes to researching valuable options for waste water treatment (Angenent et al., 2004).
- **Biogas production from anaerobic digestion:** Anaerobic digestion is a biological conversion process which is carried out in the absence of an electron acceptor such as oxygen (Angelidaki I. & Batstone D.J., 2011). The main products of this process are an effluent (or digest) residue and an energy-rich biogas. The entire conversion chain can be broken down into several stages (Figure 5), in which different groups of microorgan-

isms drive the required chemical reactions. The obtained biogas can be used either to generate power and heat or to produce biofuels. The digest can also be utilized in many different ways depending on its composition. Several technologies utilizing this process have been developed throughout the years but are still considered to be immature and not economically competitive compared to other WtE technologies.

- **Biogas production from landfills:** Other than in an anaerobic digester, it is possible to extract biogas directly from landfill sites, because of the natural decomposition of waste (Tchobanoglous et al., 2002). In order to do so, it is necessary to construct appropriate collecting systems for the produced biogas. Biogas in landfills is generally produced by means of complex bio-chemical conversion processes, usually including different phases like Initial Adjustment, Transition Phase, Acid Phase, Methane Fermentation and Maturation Phase (Zaman, 2009).
- **Microbial fuel cell:** A microbial fuel cell is a device that is able to produce electricity by converting the chemical energy content of organic matter. This is done through catalytic reaction of microorganisms and bacteria that are present in nature. This technology could be used for power generation in combination with a waste water treatment facility (Min B., Cheng S. & Logan B.E., 2005).

Chemical conversion (Esterification):

The chemical process of esterification occurs when an alcohol and an acid react to form an ester. If applying this process to WtE treatment, it is possible to obtain various types of biofuels from waste. (Nic et al., 2006).

Figure 5

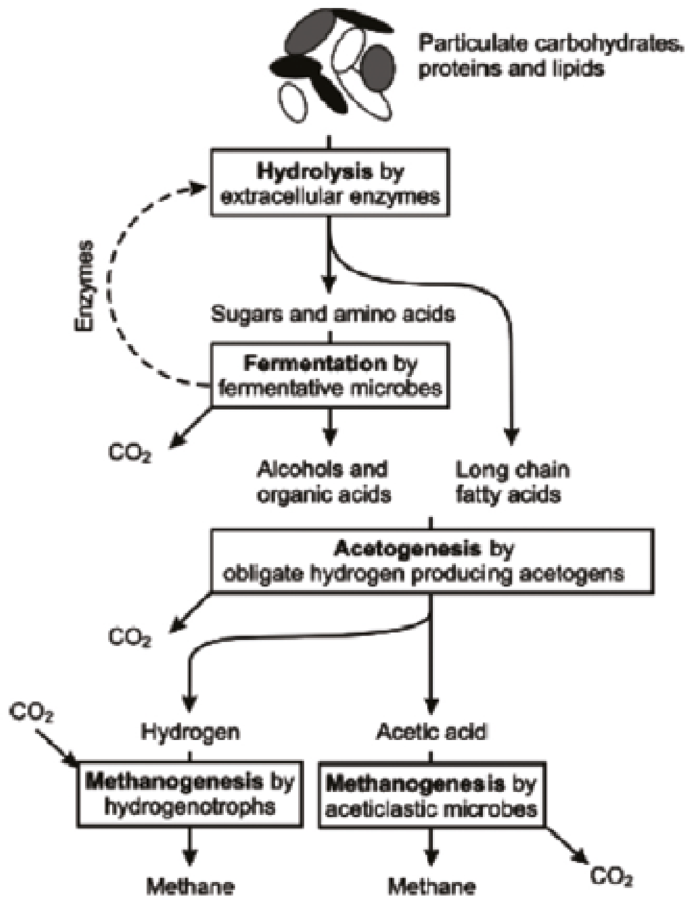


Figure 6

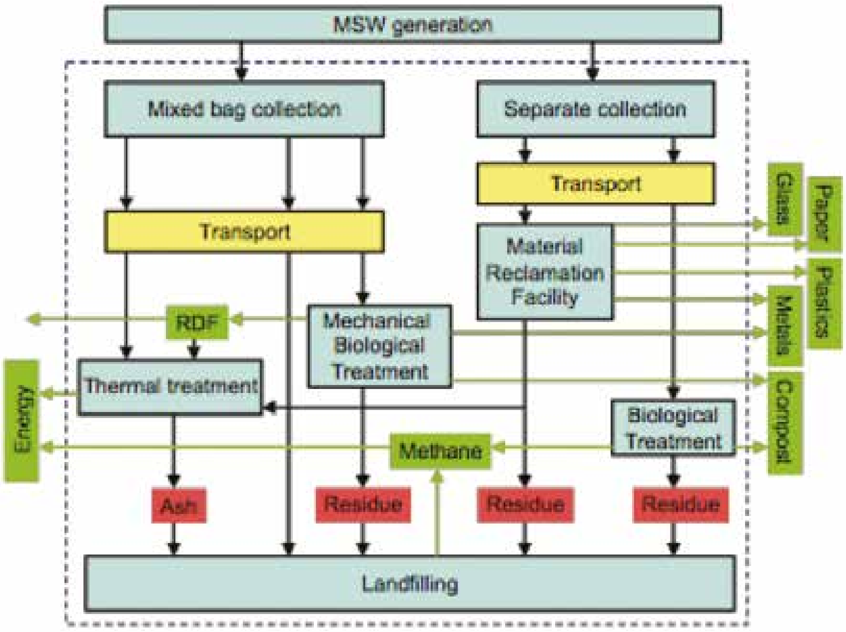


Figure 7

	Low Income Countries	Lower Mid Inc Countries	Upper Mid Inc Countries	High Income Countries
Income (GNI/capita)	<$876	$876-3,465	$3,466-10,725	>$10,725
Waste Generation (tonnes/capita/yr)	0.22	0.29	0.42	0.78
Collection Efficiency (percent collected)	43%	68%	85%	98%
Cost of Collection and Disposal (US$/tonne)				
Collection[2]	20-50	30-75	40-90	85-250
Sanitary Landfill	10-30	15-40	25-65	40-100
Open Dumping	2-8	3-10	NA	NA
Composting[3]	5-30	10-40	20-75	35-90
Waste -to-Energy Incineration[4]	NA	40-100	60-150	70-200
Anaerobic Digestion[5]	NA	20-80	50-100	65-150

NOTE: This is a compilation table from several World Bank documents, discussions with the World Bank's Thematic Group on Solid Waste, Carl Bartone and other industry and organizational colleagues. Costs associated with uncollected waste—more than half of all waste generated in low-income countries—are not included.

The current WtE market is continuously under development and these and other new technologies are likely to play an important role in the foreseeable future, as long as they can prove to be sufficiently competitive with the more traditional Incineration process from a technical, economic and environmental perspective.

LCA, including current costs, efficiencies and emissions & water for each phase: extraction, transport, processing, distribution, use

In the development of WtE projects, the consideration of the environmental implications is playing an increasingly important role. The Life Cycle Analysis (LCA) approach is more and more used as a support tool in strategic planning and decision-making process of WtE projects (Christensen et al., 2007). However, dealing with a general Life Cycle Analysis for MSW WtE systems could be a challenging task. The inputs and outputs of the WtE systems could markedly vary from project to project: in fact, the composition and cost of the waste strongly depend on the location of the project. Efficiencies and emissions can vary significantly by the WtE plant design and waste composition; so does the size of the markets for products derived from WtE facilities (Mendes et al., 2004).

Zaman (2009) presents a comparative LCA study among four of the main WtE technologies from energy generation perspective. The considered technologies are: 1. Landfill gas production; 2. Incineration; 3. Thermal Gasification; 4. Anaerobic Digestion. The study also includes the environmental impacts associated with the emissions of the analysed systems.

The cradle-to-grave life cycle of a WtE technology (Figure 6) begins with the waste generation e.g. when the owner of a product discards it in the waste collection trash cans. Then, depending on the country and/or regional laws, the waste is collected either via mixed-waste bags or via separate collection; in both cases a dedicated infrastructure for the collection is required (e.g. dedicated bins, dedicated collection vehicles, storage units, etc). The next stage is the transportation of the collected waste to the waste treatment facility: the mixed-waste bag reaches the WtE facility/plant (landfill gas production, incineration, pyrolysis-gasification, anaerobic digestion), whilst the separated waste goes to the Materials Reclamation Facility (MRF). The next stage of the life cycle is then the processing of the waste inside the WtE plant: energy in the form of heat, electricity and fuels are produced, as well as residues and ashes.

Regarding the collection, storage and transportation of the MSW, LCA studies show that the door-to-door collection system has a higher environmental impact than the multi-container collection system (Iriarte et al., 2009). Moreover, the bring systems (where individuals physically bring the waste to the collection points), although widely used in modern waste collection schemes, have higher overall environmental impacts than the curbside collection, where the collection of waste is centralised (Beigl & Salhofer, 2004). Eventually, it is believed that using bigger high-density polyethylene (HDPE) bins in the collection systems will yield a lower environmental impact than if using smaller HDPE bins (Rives et al., 2010). The costs associated with the collection and disposal of the MSW depend, of course, on the considered country. An overview of the estimated solid waste management costs by disposal method is shown in Figure 7 below.

Concerning the WtE processing, LCA studies demonstrate that landfill gas production has the highest emissions of carcinogenic substances among the considered technologies. It has respiratory effects of organic solvent exposure and presents a higher level of toxicity and an overall higher impact on climate change (Zaman, 2009). As reported by Abeliotis (2011) landfills represent the worst management option from a waste management point of view (Miliute & Staniskis, 2010; Cherubini et al., 2009; Wanichpongpan & Gweewala, 2007; Hong et al., 2006; Mendes et al., 2004). Incineration, on the other hand, has a high impact on climate change and acidification and presents respiratory effects of organic solvent exposure. The Thermal Gasification and Anaerobic Digestion processes have significant lower environmental impacts than other considered WtE options (Zaman, 2009). The LCA simulation conducted by De Feo & Malvano (2009) of 12 different MSW WtE scenarios with 16 management phases for each scenario, clearly shows that following the 11 considered impact categories, there is a different "best scenario" option for each category: the MSW WtE management options should be evaluated case-by-case.

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Luca Lo Re L
General Manager France, BNL Clean Energy
Gianmarco Piamonti
Sustainable Energy Engineer, BNL Clean Energy
Mohamad Tarhini
Business Manager, BNL Clean Energy

Reserves and production

Table 1
Municiple Solid Waste reserves and production

	Quantity raw waste			Yield of solid fuel	Electricity Generation Capacity	Annual Electricity Generation	Direct Use from Combustion	Total Energy Production
Country	TJ	TTOE	million tonnes	GJ/tonne	kW	TJ	TJ	TJ
Albania		405						
Algeria			5					
Australia			6.9	9	11.4			
Austria			2.4				16421	30270
Belgium			1.1		76600			1765
Botswana							1420	
Brazil			40		41870			2311
Canada			11.856		211187		1.688	
Croatia			1.5		2000	0.0144		
Czech Republic			0.24		3000	42	1966	2008
Denmark	40051					6718		
Egypt			2.4					
Estonia			0.569					
Finland			2.2			2160	2380	4610
France		2394			772800	13586	27209	40795
Germany			0.94		852000	11200		
Greenland				10.5			83	
Hong Kong			7.7					
Hungary			0.2	12.5		1504	28093	62993
Iceland					831	15	56	71
Ireland								1085
Israel			5					
Italy						619475	5602	
Japan			0.601		2230000			
Jordan			2		1000	5142 MWh	5142 MWh	
Korea (Republic)							21153	
Latvia					9400	106		
Lebanon			1.44					
Mexico			37.59			820		
Netherlands						10296	1085	11381
New Zealand					37800	726	280	
Philippines						6		
Poland							675	
Portugal			1		90000	7652		
Romania		545						
Senegal					20000			
Serbia			2.8					
Singapore					135000	3994.68		
Sweden					282	4990		

Switzerland			3316		13562
Syria	4				
Taiwan		583.8	27128.9		
Thailand		5000	94.63		
Turkey		59.65	220		
Ukraine	19.57				
United Kingdom	3.8	375900	7061	2108	9169
United States of America	254	2669000	54255	20833	75088
Uruguay		1000			

County notes

Country Notes for Waste Chapter of the World Energy Resources report are currently being compiled as a subset of the Bioenergy Chapter.

8

Solar

Contents

Strategic insight

1. 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.

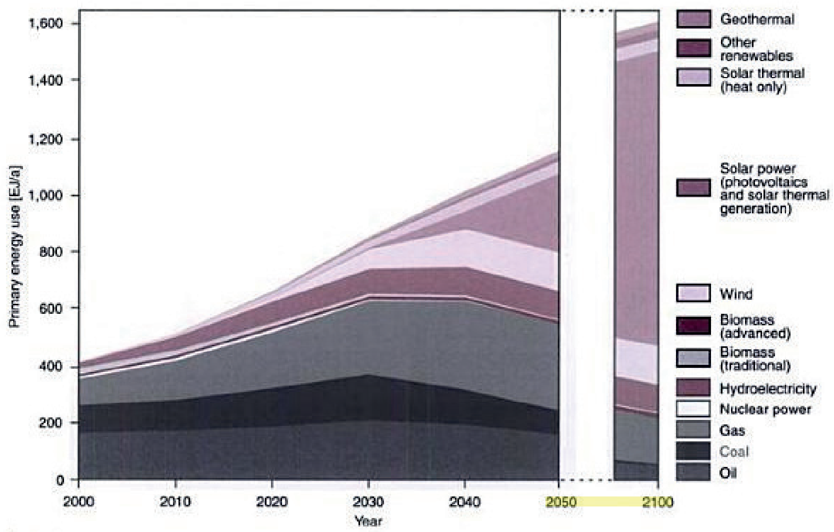
The sun emits energy at a rate of 3.8×10^{23} kW per second. Of this total, only a tiny fraction, approximately 1.8×10^{14} kW is intercepted by the earth, which is located about 150 million km from the sun. About 60% of this amount or 1.08×10^{14} reaches the surface of the earth. The rest is reflected 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 solar radiation reaching the earth's surface in just one year, 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 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 policies and plans to obtain 20% of its energy needs through renewable energy by 2020. The German Advisory Council on Global Change (WBGU) has 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

Figure 10.1
Transforming the global energy mix: the exemplary path to 2050/2100
Source: WBGU, 2003



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 during the last century and the ongoing research and development.

By 2100 oil, gas, coal and nuclear, as shown in Fig. 10.1 (above), 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.

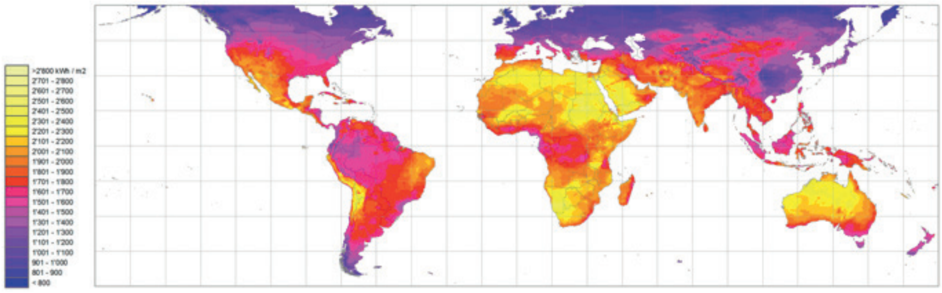
Solar Radiation Resources

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 1366.1 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

Figure 10.2

Yearly sum of global horizontal irradiation, 1986-2005

Source: www.meteonorm.com



m³ 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/m² can be found in the Red Sea area, and typical values are about 200 W/m² in Australia, 185 W/m² in the United States and 105 W/m² 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. Figure 10.2 shows the world yearly sum of global horizontal irra-

Figure 10.3

Average daily solar radiation for March

Source: NASA/SSE

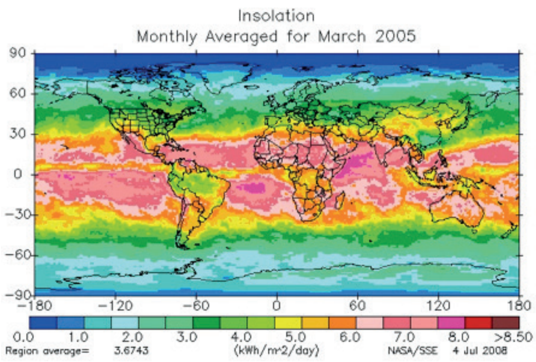


Figure 10.4

Average daily solar radiation for July

Source: NASA/SSE

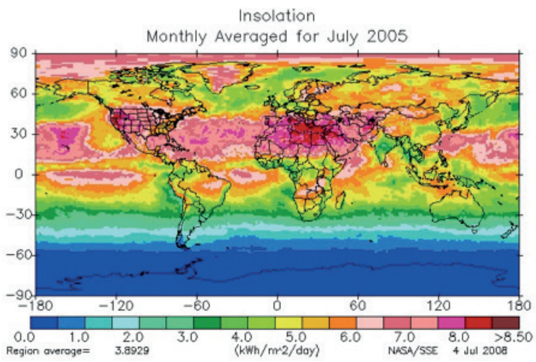


Figure 10.5

Average daily solar radiation for September

Source: NASA/SSE

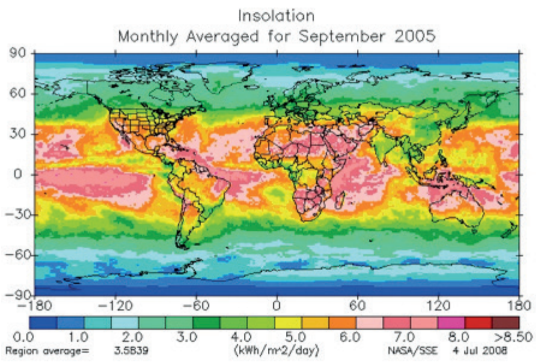
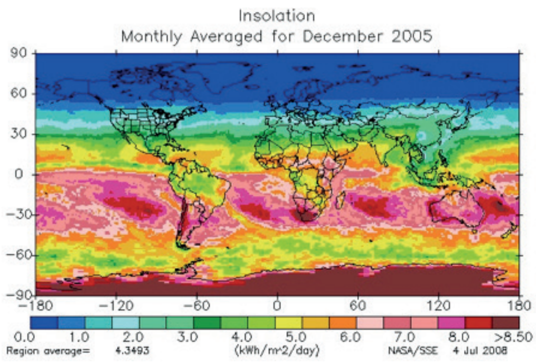


Figure 10.6

Average daily solar radiation for December

Source: NASA/SSE



diation. Figures 10.3 to 10.6 also show the monthly solar energy falling on the Earth in the months of March, July, September and December.

In a period of rapidly growing deployment of solar energy systems, it is imperative that solar 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 fluids, 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 500°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 1000C or even higher. Therefore, they are used to produce electrical power and as high-temperature furnaces in industrial processes. Solar thermal power plants based on these concentrating solar collectors, also known as Concentrating Solar Power or CSP is now being increasing considered and deployed by electrical utilities in the size range of 1 MW to 300 MW in many countries, including USA, Spain, India, China, Australia and South Africa.

PV panels are solid-state and are therefore very rugged, with a long life. At present, panels based on crystalline and polycrystalline silicon solar cells are the most common. However, thin-film solar panels, especially cadmium telluride (CdTe) and copper indium gallium diselenide (CIGS) are gaining market share because of their lower costs. Their efficiencies have gradually increased, while costs have decreased. For example, the efficiencies of multijunction cells and concentrating PV have been reported to be as high as 44%, and most panels available in the market have efficiencies of the order of 15%. The price of PV panels came down from about US$ 30/W about 30 years ago to less than US$ 1/W in 2013. Although thin-film solar cells increased their global market share in the last decade because of lower cost , manufacturers have been able to reduce the cost of producing silicon based solar panels to match the thin film panel costs. Therefore, silicon based panels have kept their market share close to 80%. To evaluate the efficiency of solar energy systems, a standard flux of about 1000 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).

2. Technical and economic considerations

Solar Collectors

Solar thermal collectors are used to heat air, water or other fluids, 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 100C 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 100C to about 500C. 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 1000C or even higher. Therefore, they are used to produce electrical power and as high-temperature furnaces in industrial processes. Solar thermal power plants based on these concentrating solar collectors, also known as Concentrating Solar Power or CSP is now being increasing considered and deployed by electrical utilities in the size range of 1 MW to 300 MW in many countries, including USA, Spain, India, China, Australia and South Africa.

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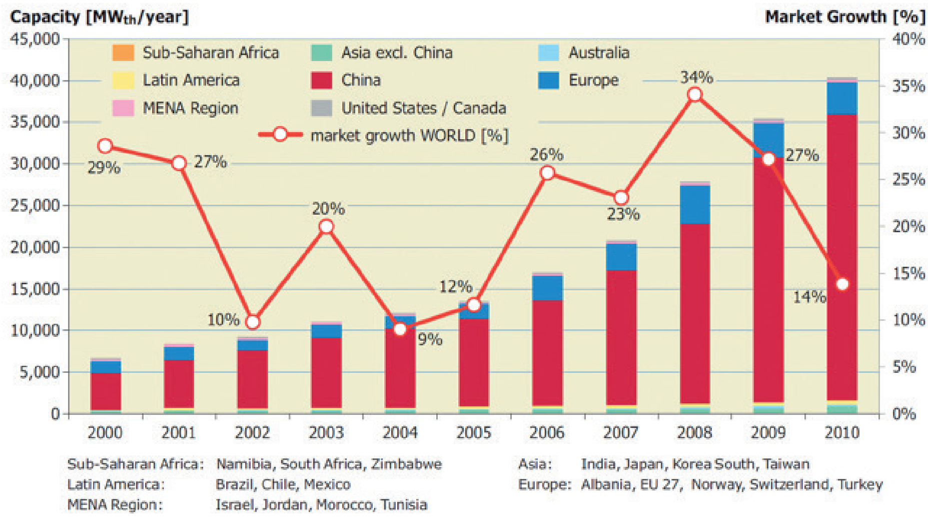
Figure 10.7
Worldwide market for glazed solar water heaters of flat plate and evacuated tube collectors from 2000 to 2010
Sources: IEA SHC



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, PV 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.

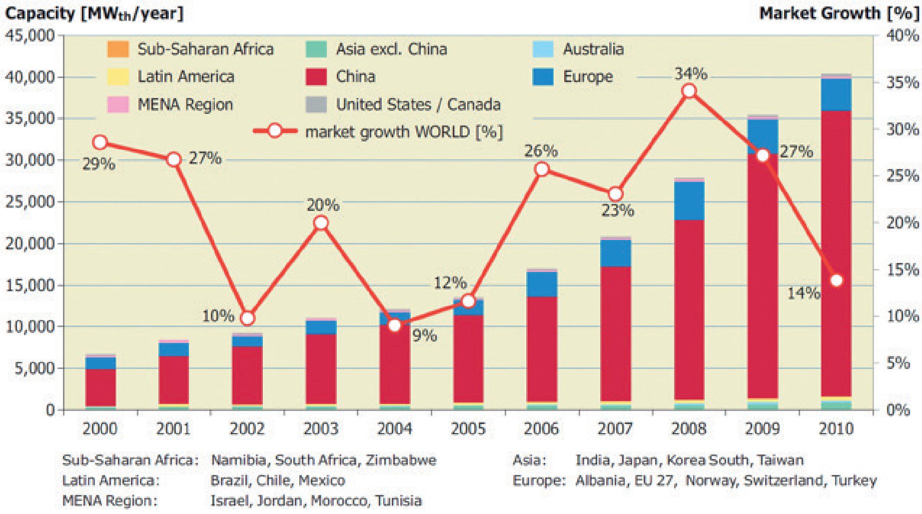
Solar water heating is the most developed solar technology and is very cost-effective when life-cycle costs are considered. However, the initial costs (capital investment) of solar water heaters are many times higher than those for electric water heaters. Therefore, most people opt for electric water 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 an average rate of more than 25 % per year, as shown in Fig. 10.7, although the rate of growth went down in 2009 and 2010 due to global economic downturn.

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 250C, which can 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

Figure 10.8
Examples of Building Integrated Photovoltaics
Source: http://construible.es/



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 would otherwise be. Fig.10.8 shows examples 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 secret behind several success stories in the use of solar thermal collectors:

Figure 10.9
The Japanese Cosmotown Kiyomino SAIZ housing development
Source: Goswami

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. 10.9 (overleaf). 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)

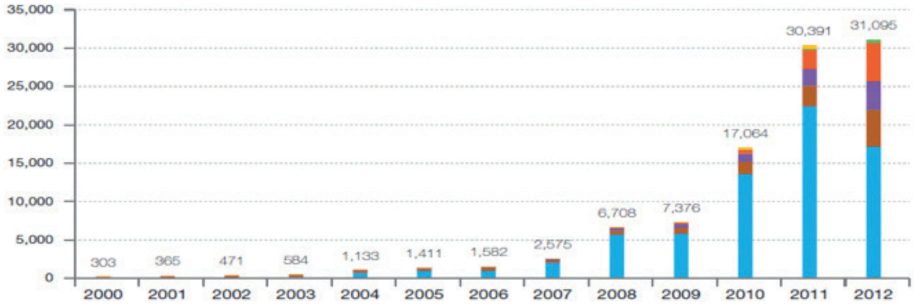
Photovoltaic conversion is the direct conversion of sunlight into electricity with no intervening heat engine. As indicated above, photovoltaic devices are rugged and simple in design and require very little maintenance. Perhaps the biggest advantage of solar photovoltaic devices is that they can be 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 multi-megawatt scale power plants. With such a vast array of applications, the demand for photovoltaics is increasing every year. In 2012, over 31 000 MWp of photovoltaic panels were sold for terrestrial uses and the worldwide market has been growing at a phenomenal rate since 2000 (Fig. 10.10 overleaf).

In the early days of solar cells in the 1960s and 1970s, more energy was required to produce a 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

Figure 10.10

Worldwide market for photovoltaic panels

Source: EPIA and P. Maycock



	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
ROW	88	56	80	77	29	10	105	42	76	80	284	508	-*
MEA	n/a	n/a	n/a	n/a	1	n/a	n/a	1	1	22	46	121	410
China	19	5	19	10	10	8	10	20	40	160	500	2,500	5,000
Americas	24	32	47	66	104	106	150	213	346	543	1,029	2,179	3,758
APAC	117	140	191	230	282	303	324	271	535	742	1,583	2,672	4,769
Europe	56	133	135	202	707	984	992	2,028	5,710	5,830	13,622	22,411	17,159
Total	**303**	**365**	**471**	**584**	**1,133**	**1,411**	**1,582**	**2,575**	**6,708**	**7,376**	**17,064**	**30,391**	**31,095**

increased to over 30 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 retail cost of solar panels results in system costs of US$ 2.5-4/W which is cost effective for many Building Integrated applications. For MW-scale PV systems, however, the system costs have come down to less than US$ 2/W which moves the technology closer to cost effectiveness for on-grid applications considering their long lifetimes (over 25 years), no fuel costs and low maintenance costs. 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.

Figure 10.11

World record efficiencies of various PV technologies

Source: NREL

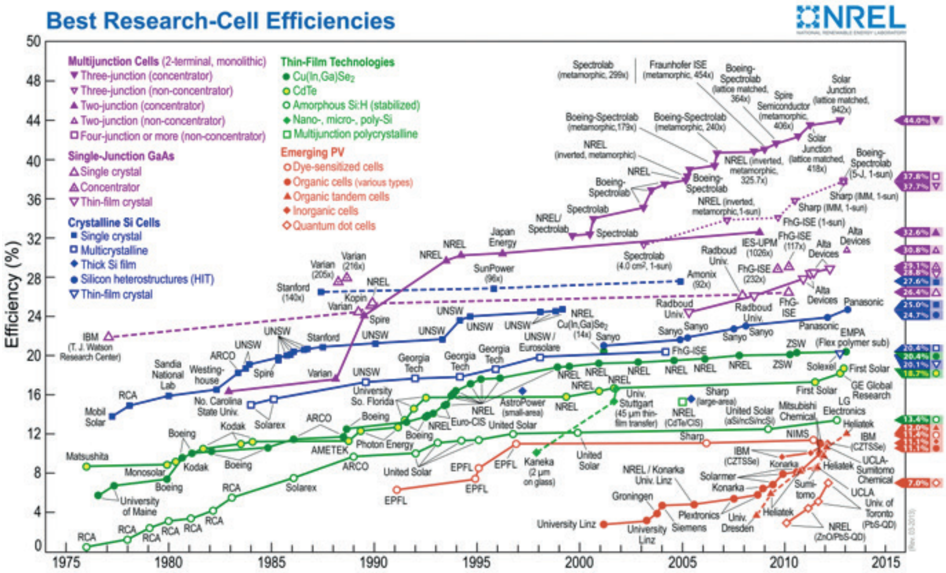
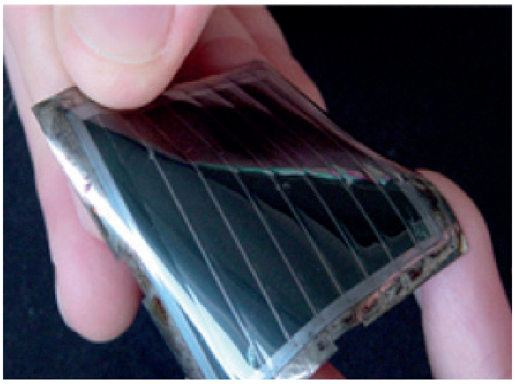


Figure 10.12
Flexible monolithic CIGS prototype mini-module on a polymer foil
Source: Goswami



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 CIGS 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. 10.11 (above). 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 (44%) 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-junction cell efficiency is nearly 44%. 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. 10.12) 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 200oC to 1000oC 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

Figure 10.13
Flow diagram for a typical solar thermal power plant
Source: Goswami

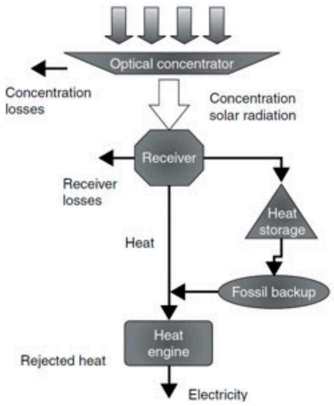


Figure 10.14
Schematic diagrams of the four types of Concentrating Solar Power (CSP) systems
Source: Goswami

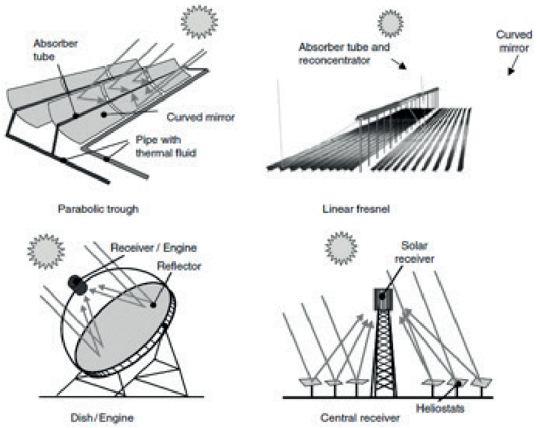
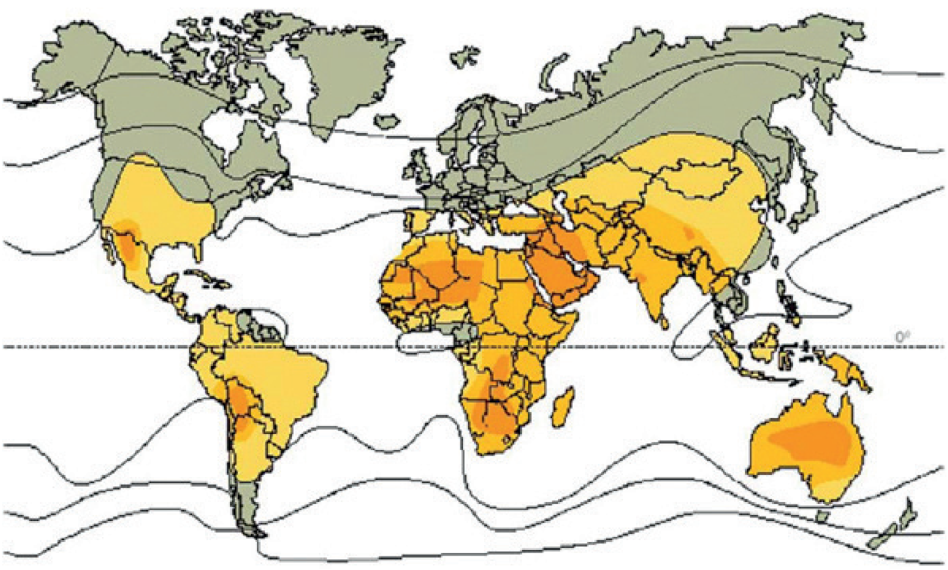


Figure 10.15
Regions of the world appropriate for Concentrating Solar Power (CSP)
Source: European Commission



of the intermittency of sunlight. Fig. 10.13 explains the concept of a solar thermal power plant operating with storage and/or a backup fuel. Fig. 10.14 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. 10.15 (overleaf). 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, China and Australia.

CSP capacity of 364 MW was installed in California in 1990 (Figs. 10.16 and 10.17; pages 14 and 15), most of which (354 MW) is still operating. Each year the performance of the plant has

Figure 10.16
Parabolic-trough based solar thermal power plant in California (power plant [left]; parabolic trough collectors [right])
Source: Goswami


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 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 in USA and around the world, which when completed will increase worldwide capacity to about 3 000 MW.

The reported capital costs of Solar Thermal Power plants have been in the range of US$ 3000-3500/kW, although less than $2500/kW costs are being quoted now. These costs result in a cost of electricity of around US$ 0.15/kWh. Based on ongoing research and development, the capital costs are expected to decrease to below US$2000/kW and the capital cost of thermal energy storage is expected to decrease to less than $15/kWhth from the present costs of about $30/kWhth, which will bring solar thermal power closer to conventional power, even without considering the environmental costs/benefits.

New generation of solar thermal power systems are 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. At the same time, central receiver tower, also known as "Power Tower" technologies are being developed to achieve temperatures of more than 10000C and to run on "combined cycle" or a supercritical CO_2 cycle. Active research on central receiver tower technologies is underway in USA, India and other countries.

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. By adding Thermal Energy Storage to a CSP plant, the levelized cost of energy (LCOE) from such plant can go down by as much as 30%.

Figure 10.17
Central receiver power plant in California
Source: Goswami

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 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.

3. Market trends and outlook

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, India; the Renewables Portfolio Standard (RPS) adopted by the majority 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, new thermodynamic combined cycles, and efficient low-cost thermal energy storage 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
International Solar Energy Society
Saeb M. Besarati
Clean Energy Research Center, University of South Florida

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Global tables

Table 10.1
Installed Capacity (MW) in 2011

	Solar PV		Solar Direct	
	Installed capacity	Actual Generation	Energy Prod (Active)	Energy Prod (Passive)
Country	MW	GWh	TJ	TJ
Argentina	16			
Australia	1 400			
Austria	187	174	6 930	5 445
Bangladesh	46			
Belgium	1 391			
Brazil	1	2	2 500	
Bulgaria	153	0		
Canada	559	1	1 770	n/a
China	3 300			
Croatia	0	0	254	n/a
Cyprus	10			
Czech Republic	1 971	2 182	366	n/a
Denmark	17			
Egypt	20			
Ethiopia	5			
Finland	11	8	39	
France	2 760	2 400		
Germany	25 039			
Greece	612			
Guadeloupe	65			
Hong Kong	1			
Hungary	2			
India	941			
Indonesia	1	1		
Ireland	0			
Israel	61			
Italy	12 773	11	2 151 751	
Japan	4 914			
Korea (Republic)	730			
Latvia	0			
Lithuania	0			
Luxembourg	41			
Malaysia	68			
Malta	7			
Martinique	14			
Mexico	37	38	15	
Monaco	0	0	1	
Netherlands	145			
Norway	9			
Peru	4			

Poland	1	0		
Portugal	172	278	2 604	
Réunion	145			
Romania	1	1		
Russian Federation	0			
Slovakia	188			
Slovenia	57			
South Africa	2			
Spain	4 332			
Sri Lanka	1			
Sweden	16	0		
Switzerland	192	149	1 655	406
Taiwan	19			
Tanzania	2			
Thailand	67			
Turkey	4	6	420 000	
Ukraine	190			
United Kingdom	976			
United States of America	5 171			
Total World	**68 850**	**-**	**-**	**-**

Country notes

The following Country Notes on Solar provide a brief account of countries with significant 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 figures in Table 10.1 relate to 2011 to ensure comparability between the countries. The figures in country notes are the most recent available.

Australia

Total Solar Capacity MWe in 2011	1 400
Solar Capacity added in 2011 MWe	837

Australia represents 2% of the global solar market and was the only non European country besides China and Japan to have added at least 1 000 MW of PV capacity in 2012, which means that PV capacity in Australia has increased by about 400% in just 2 years. Today, the Australian Renewable energy industry employs more than 24 000 people, 17 000 of which work in the solar industry.

The solar industry is equally distributed across the Australian Continent. New South Wales has about 500 MW of solar capacity as of December 2012. Victoria has about 400MW while South Australia and Western Australia have PV installations with peak capacities of 341MW and 283MW respectively. Small scale solar projects dominate the PV industry and CEC reports that more than 10% of the households have installed solar panels in their rooftops.

Large Scale solar projects remain few and account for less than 0.5% of the total clean energy generation in Australia. Only 39 large "large scale" solar plants are currently in operation with the largest of 10MW capacity located in Western Australia. The Australian Renewable Energy Agency, which operates under the Ministry of Resources and Energy, has provided hundreds of millions of dollars in funding for large scale solar projects such as the Broken Hill and Nyngan project with the cost of 170 million AUD and capacity of 159MW. Another large project which is under way is located in Victoria with a capacity of 100 MW. It will use solar concentrator technology rather than Photovoltaic.

Australia has many feed in tariffs for solar installation depending on the territory. The State of Victoria for example has adopted a flat rate of 0.08AUD regardless of the size of the installation. On the other hand, in South Australia the rate is 0.16 AUD for the first 45 kWh exported back to the grid. If the permission to connect to the grid is received after 30th September 2013, the customer will not get any feed in tariff. Customers will then qualify for "minimum retailer payment" which currently is 0.098 AUD per KWh. This rate is subject to review after 2013. Queensland has the most generous feed in tariff of 0.44 AUD per KWh but to qualify, strict requirements should be met. For example, the house must not use more than 100MWh of electricity each year.

Belgium

Total Solar Capacity MWe in 2011	1 391
Solar Capacity added in 2011 MWe	996

Belgium represents about 2% of the cumulative global solar market as of 2013 and was the 11th largest solar market in 2012. Belgium added nearly 1000 MW of solar capacity in 2011, but only about 600MW the following year. The reason for this decline is that the country had a national target of 1 340 MW of Solar Capacity by 2020 which was reached in 2011. Belgium has the potential to reach 7 000 MW of solar capacity by 2020.

Belgium is one of the few European nations not to operate any large scale PV power plants. Over 60% of the PV capacity is in residential installations. 20% of installations are commercial and a further 18% of solar capacity is in the industrial sector. Of the 599MW of solar capacity added in 2012, nearly 500MW was in the residential sector and the rest was split between the commercial and industrial sectors.

Since Belgium has already reached its 2020 target, the government has decided to reduce feed in tariff incrementally to focus on other areas of the economy. In the first half of 2011 the feed in tariff was 0.33€/kWh which was reduced to 0.30€/kWh in July and finally to 0.27€/kWh in October. In 2012 the Belgian government decided to reduce the tariff by 2 cents every 4 months.

Chile

Total Solar Capacity MWe in 2011	4
Solar Capacity added in 2011 MWe	4

The Solar Energy market in Chile is still in the early stages of development with most of electricity being generated by fossil fuels and hydro. However, Chile is home to the Atacama Desert, the driest desert in the world with an annual rainfall of only 0.6mm. According to an extensive study conducted by “Global Energy Network Institute” (GENI) the Atacama Desert has the highest solar irradiance in the world. GENI has also estimated that if a very large hypothetical solar power plant was to be built in Atacama desert, it can potentially have a capacity of 3 000 GW using solar cells with only 8% efficiency.

Business interest in solar has remained relatively low over the last decade and Chile continues to be one of the smallest market for solar energy. Some business activity has taken place. First Solar has purchased “Solar Chile”, which was a state controlled firm to promote solar investments. First Solar plans to invest USD370 million to build a solar power plant in the Atacama Desert, with an estimated capacity of 162 MW. The Environmental Evaluation Service, which is part of the Ministry of the Environment, is the entity which normally approves solar projects. It has approved nearly 4 000 MW of solar projects and more than 2 000 MW of projects are currently under review.

China

Total Solar Capacity MWe in 2011	3 300
Solar Capacity added in 2011 MWe	2 500

China represents 8% of the global solar market and is the largest market for solar outside Europe. Since 2011 China has nearly tripled its solar capacity from cumulative capacity of 3300MW in 2011 to over 8000 MW as of 2013. By 2020, China intends to install about 50GW of solar capacity. This high growth in recent years can be explained by the action of the Chinese government to mitigate coal pollution which affects millions of people each year. China decided to spend USD45 billion a year from 2010 on renewable energy in an effort to reduce its dependence on coal.

China has abundant potential for solar energy, since 17% of mainland China receives annual solar radiation of more than 1750 Kwh/m^2 and more than 40% of China receives between 1400-1750KWh/m^2. The Gobi desert in China has an area of 1.3 million square km and if it was covered in photovoltaic cells, it would have a potential capacity of 17 TW. However the regions that receive the most sunlight are predominantly rural and relatively far from the national power grid.

China has become the world's largest solar cell manufacturer, producing more than 10GW worth of solar cells in 2010 alone. China exports 95% of all solar modules. Ten companies now control more than half of the global production for solar modules and 4 of these are Chinese, namely, Suntech, JA solar, Yingli green energy and Trina solar. China is one of the largest exporters of solar modules to the United States with exports worth about USD2.8 billion worth of solar cells in 2011 alone. In 2008 the average selling price of solar cells produced by Chinese companies was just over USD4 per Watt or twice as much as the global average, whereas just two years later, the price dropped to about USD1.80 per Watt, 30 cents lower than the global average.

Czech Republic

Total Solar Capacity MWe in 2011	1 971
Solar Capacity added in 2011 MWe	6

The Czech Republic has over 2000 MW of installed PV capacity. Since 2010, additions to the Czech Republic's solar power sector have been small. The reason for this is the decision by the government to reduce subsidies by 25%, since the country had already reached its national solar target of 1 695 MW in that year. The Czech Republic was one of the two countries in the European Union to reach its "National renewable energy action Plan" ten years in advance of the target date. The EPIA also estimates that the Czech Republic has a potential market of 241 MW annually and therefore should easily achieve 4 000 MW of solar capacity by 2020.

More than 60% of the installed capacity is in the residential sector. In 2012 out of the 113MW of solar capacity added to the national grid, more than 50MW was added in the commercial sector and no large or utility scale plants were added. About 56MW of residential solar was also added to the grid in 2012. In 2011 total installed PV capacity was about 10% of the total, but PV contribution to total electricity generated in the country in the same year was only 3%. The Czech Republic has a target of generating 13.5% of total electricity by 2020 from renewables.

France

Total Solar Capacity MWe in 2011	2 924
Solar Capacity added in 2011 MWe	1 756

France accounts for slightly less than 4% of global cumulative PV capacity. However in just 2 years solar capacity has almost quadrupled in France from 1168MW in 2010 to 4003MW in 2012. France was the 3rd largest market for PV in Europe in 2012 and was the 6th largest market in the world narrowly ahead of Australia.

About half of France's PV capacity is in the commercial and the industrial sector while utility sized PV farms represent 30% of the cumulative PV installations. The remaining 20% of the cumulative PV market is residential. Of the 1079MW of PV added in 2012, about 320MW was in the form of Utility sized power plants the largest of which was built by EDF Energy in north eastern France called the "toul-Rosieres solar park" with a peak capacity of 115MW. Completed in 2012, it was the largest solar park in Europe and one of the largest in the world.

France has a target of installing 4860 MW PV capacity by 2020 therefore it only needs to install just over 100MW of capacity every year to reach it. EPIA however estimates that France has a potential market of over 3000 MW every year therefore should be able to have 20-25 GW of solar capacity by the year 2020.

The French government uses two mechanisms to help facilitate the development of solar. A feed in tariff scheme is used to finance the small scaled solar projects. This can range from 0.289€/kWh to 0.46€/kWh for installations with a peak capacity of up to 100kW. All installations with a capacity between 100kW and 12MW are eligible for feed in tariff of 0.12€/kWh.

Germany

Total Solar Capacity MWe in 2011	25 039
Solar Capacity added in 2011 MWe	7 485

Germany is currently the global market leader in solar power. The Photovoltaic market has been growing at a spectacular pace since the turn of the century, partly due to government subsidies. With over 32 GW of installed capacity, Germany accounts for over 30% of global solar capacity. While global solar capacity increased from just over 70 GW in 2011 to 100GW in 2012 (approximately a 40% increase), Germany's solar capacity increased by 7604 MW, an increase of about 30%. According to the National Renewable Energy Action plan, Germany has a target of 50GW for solar power by 2020, but by 2020 it is expected to reach 80GW of installed capacity. According to the German Ministry of Economy, the total electricity production is 125 GW; solar therefore represents approximately 25% of the German electricity market.

The German Federal government has shown considerable interest in the Research and Development of solar and in 2011 it granted more than 70 million Euros for 96 R&D projects in solar. The positive investor environment for the solar industry can be seen by the number of international companies that have built factories in Germany, including "Masdar PV", a company based in UAE, which has built a module manufacturing facility.

According to Global Equity Research by UBS solar power has already reached grid parity in Germany, and over the course of next 5 years, the retail price of electricity is expected to increase faster than the solar. UBS estimates that by 2020, solar power would be about 25% cheaper than conventional electricity in Germany.

Germany has one of the largest solar power plants in the world with “Solar Park Meuro” being the largest with a peak generation capacity of 166MW it was completed in 2012. Another solar park completed in 2012 was Neuhardenberg Solar Park with a peak capacity of 145 MW.

India

Total Solar Capacity MWe in 2011	941
Solar Capacity added in 2011 MWe	190

India is expected to become one of the largest markets for the solar power industry. The federal government’s plan to have 20GW of solar capacity in the country by 2022 has been widely taken up at the state level.

India added slightly less than 1 GW of solar capacity in 2012, a considerable increase on the 190MW added the year before. The largest solar power plant in India is in Gujarat, Western India. With a peak capacity of more than 200 MW, it is the third largest solar power plant in the world built by Gujarat Power Corporation. Currently the state of Gujarat has about 850MW of PV installed. Other states with high solar irradiance have developed a number of solar projects in the last few years such as the state of Tamil Nadu, which has a regional target of 3 GW of solar capacity by 2015 according to Mercom Capital Group, a market research company based in Bangalore. Maharashtra has 160 MW of solar capacity installed and the state government has plans under way to install more in the coming years.

According to a report published by KPMG last year, the Indian government has several mechanisms to promote the growth of its solar industry. One of which is the exemption from customs and excise duty on products to be used in a solar project. Renewable energy plants built before 31st March 2013 have been allowed a 10 year “tax holiday”. The federal government has also introduced “generation based incentives” such as a feed in tariff for solar INR 12.41 per kW/h for independent power producers. Under the guidance of the Ministry of New and Renewable Energy, an Energy Development Agency has been set up with the sole purpose of financing renewable energy projects across India. The most proactive measure taken by India to increase the share of renewable energy is the enactment of the “Renewable Purchase Obligation Programme”, which compels distribution companies, open access consumers and captive consumers to purchase a certain proportion of their power from renewable energy sources.

According to IRENA, in 2011 the average cost of solar system with 5 to 10 kW of capacity in India ranged between 2.5 - 3.0 USD per Watt. The average price of large scale solar plants was just under 2.4 USD per Watt. The cost of PV dropped very little in the following year, as IRENA reported in its 2012 report that the average cost of large scale PV is about 2.2USD per watt.

Italy

Total Solar Capacity MWe in 2011	12 773
Solar Capacity added in 2011 MWe	9 454

Italy is one of the largest players in the global solar market with about 16% share. In 2012 3.4 GW of capacity was added to the grid which was significantly lower than the 2011 figure. According to the European Photovoltaic Industry Association, a lot of the PV systems were installed at the end of 2010 but connected to the grid only in 2011. New PV installations in 2010 were about 4-5 GW, in 2011 about 6-7GW and in 2012, roughly 3.5GW of PV was installed.

According to the IRENA, the average size of a utility scale PV plant was about 13 MW. The price of PV per watt was approximately 5 USD. Between December 2010 and August 2011, ABB has built solar parks with a total maximum capacity of 100MW. This was done in collaboration with Renewable Energy Corporation (REC) BNP Paribas.

The Italian Ministry of Economic Development released a press release on 12 of October 2012, in which it laid out a new "National Energy Strategy" with the intention to address energy costs and the environment. The Ministry expects the wholesale sale price of all energy sources to be in line with the European price levels. The Italian government also has a target to increase the share of renewable energy sources from 10% in 2010 to 20% by 2020.

Japan

Total Solar Capacity MWe in 2011	4 914
Solar Capacity added in 2011 MWe	1 296

Japan is the second largest market for solar energy in Asia after China. It accounts for about 7% of the global solar market and added 2 GW of solar capacity in 2012, up from 1296 in 2011. After the Fukushima nuclear incident, the Japanese government was forced to reconsider its energy policy and as a result set a target for solar energy of 28GW by 2020. Consequently, Japan is expected to break the record for aggregate solar capacity installed in a single year in 2013.

Japan has one of the largest markets for small scale PV projects and unlike in Europe, the share of small scale PV projects has increased significantly. Spending on small scale solar projects was just over 8 billion USD in 2011 and 13 billion USD in 2012, an increase of 56%, according to the report published by the Frankfurt School UNEP Centre titled "Global Trends in Renewable Energy Investments" The average cost of small PV systems is just over 6 USD per Watt, one of the highest costs in the world and substantially higher than the small PV systems in China, which is about 0.90 USD according to the "Renewable Energy Technologies: Cost Analysis" published by IRENA.

According to RTS Corporation, a consultancy based in Tokyo, the Hokkaido region in Northern Japan is the largest sub national solar market. Residential solar power accounted for more than 80% of the Japanese solar market and utility sized power plants represented less than 5% of the market. In mid-2012 the Japanese government reintroduced subsidies to boost further investment in solar power. The feed in tariff starts at JPY 40 (0.42 USD) per kilowatt hour for large installations.

Mitsubishi Electric is one of the largest manufacturers of solar cells in Japan. It had started research and development in solar power back in 1974 and since then has grown to become one of the major industry players. In 2010 Mitsubishi Electric created the most efficient polycrystalline cells with the efficiency of 19.3%. Kyocera Solar, Kaneka and Sharp Solar also hold significant share in the Japanese solar market.

Pakistan

Total Solar Capacity MWe in 2011	< 1
Solar Capacity added in 2011 MWe	< 1

Pakistan is one of the few countries that has huge solar potential but yet no government plan to facilitate the growth of solar energy. Pakistan is home to part of the Great Indian Desert (Thar), with about 77 000 sq miles of land area.

There has been a change of government in May 2013 and it is possible that solar energy may be revisited in the coming years. The newly elected Prime Minister has stated that there is a 3 GW shortfall in the electricity supply, and country needs to increase its total capacity from 16 GW to 19 GW. A Korean Company of “CK Solar” has expressed interest in investing in large scale solar power plant in the province of Baluchistan. With a planned capacity of 300 MW, it would be the largest solar power plant in the world and would potentially kick start the development of a solar industry in this country.

Spain

Total Solar Capacity MWe in 2011	4 890
Solar Capacity added in 2011 MWe	472

The Spanish solar market represents about 5% of the global PV market and in recent years its growth has slowed down significantly compared to rest of Europe. This decrease in growth can be explained by the end of all subsidies to solar energy in 2012 as a result of a wider economic review by the Spanish government. According to the European Photovoltaic Industry Association (EPIA), Spain’s national target for solar capacity is 8,367 MW by 2020. With over 5GW already installed, the EPIA estimates that Spain only needs to add 400MW of solar capacity every year to reach the necessary target. The EPIA also estimates that Spain should be able to add over 1500 MW of solar energy every year.

According to IRENA, Spain has a target to meet 3% of total energy demand from solar by 2020. The report goes to say that Spain has a target to generate 38% of its electricity from renewable energy by 2020 however by 2011 Spain already surpassed that target and more than 40% of its electricity is was being generated through renewable energy in that year.

Spain has one of the highest levels of solar irradiance in Europe. With some regions receiving 2000 kWh per square metre annually, Southern Spain receives sunlight comparable to Northern Africa making this part of the country particularly suitable PV deployment.

According to EPIA, ground mounted solar farms account for about 80% of the total Spanish solar market and the rest of solar capacity is built for commercial and industrial use. Spain’s residential solar market is only about 1% of the national solar market.

The largest PV power plant in Spain is the Olmedilla Photovoltaic Park which was completed in 2008. It has a peak capacity of 60MW and at the time of completion it was the largest solar plant in the world. A larger solar power plant in the South Western near Cadiz is currently being built by Tentosul and when completed, it will have a peak capacity of 250 MW. This project is the first unsubsidised utility-scale solar project in Spain with an estimated cost of €275 million.

Castilla La Mancha is the largest regional market with about 1000 MW solar capacity installed, Andalucia is the second largest with over 800 MW. Other regions which have significant amount of solar installations include Castilla y Leon, La Comunidad Valenciana, Extremadura and Murcia. All four of these regions have more than 300 MW of installed capacity each.

United Kingdom

Total Solar Capacity MWe in 2011	904
Solar Capacity added in 2011 MWe	813

The United Kingdom represents just under 2 % of the global solar market; 1 GW of solar was installed in 2012. Most of the additions in the solar market happened in the last three years. The United Kingdom has a national target to generate 15% of its total energy from renewable sources by 2020. It also has a solar target of 2 680 GW by 2020, which EPIA estimates should be reached by 2014.

More than 50% of the British solar market is residential and approximately 23% of the solar capacity installed is utility-scale. Of the 925 MW of solar capacity added last year, more emphasis was seen in the power generation market with over 35% (323 MW) installed as ground mounted projects. However a further 400 MW of residential installations were also recorded. The EPIA reports that the UK needs an annual capacity increase of just over 100 MW solar to reach its target. The EPIA estimates that the United Kingdom has the potential to add more than 2.5 GW of solar capacity every year and by 2022, the total installed capacity of solar could reach 22GW.

The government introduced incentives for solar producers in April 2010 at the rate of 41.3p per kWh for all grid connected electricity. Currently however the incentives for solar depend very much on the size of the installation. Systems smaller than 4 kW receive a feed in tariff of 14.9p /kWh; larger systems attract a smaller tariff. For systems between 250kW and 5MW the feed in tariff is only 6.85p per kWh. The government has stated it will increase these feed in tariffs in October 2013 for all scales of systems.

Ukraine

Total Solar Capacity MWe in 2011	190
Solar Capacity added in 2011 MWe	188

Ukraine is one of the smaller markets for solar energy in Europe. Most of the solar capacity was added in the last two years although further capacity is planned. The Ukraine is notably the home of the one of the largest solar parks in Europe: the “Perovo Solar Park”. Constructed by Vienna based developer, Activ Solar, it has an estimated peak capacity of 105 MW costing a total of €387 million according to Bloomberg. Activ Solar has completed other solar projects in Ukraine such as the Ohotnikovo Solar Power station located in the Crimea region. It has the peak capacity of 82.65 MW and was completed in October 2011. The third largest solar power station in Ukraine was also built by Activ Solar, based in the Odessa Region called the “Priozernaya solar power station” finished in March 2013 with peak capacity of 54.8 MW.

In recent years legislation promoting renewable energy in the Ukraine such as the “Green Tariff Law” has encouraged the growth of the solar industry. The resulting feed in tariffs are among the highest in the world. For installations larger than 100kW capacity, the feed in tariff is 2.68 UAH per kWh, which is about 0.32 USD. It increases at peak times to 4.84 UAH per kWh, equivalent to 0.60 USD. For installations smaller than 100 kW the basic rate is the same however at peak times the feed in tariff is 4.63 UAH per kWh.

United States of America

Total Solar Capacity MWe in 2011	5 171
Solar Capacity added in 2011 MWe	1 867

The United States accounts for just under 8% of the global solar market. However a report published in June 2012 by the United States Congress estimated that by the end of 2012, the United States would have at least 10% of the global solar market. In 2012 the solar market has doubled compared with 2011 in terms of capacity added on a yearly basis. The United States was the third largest PV market after the European Union and China. California is the largest solar market within the US with over 1 GW of new solar power installed in 2012 alone. About 700 MW was installed in Arizona in 2012.

The largest solar power plant in United States is the “Agua Caliente Solar Project” in Yuma County, Arizona with a peak capacity of 250 MW and is one of the largest in the world. This plant was constructed by First Solar and operated by NRG Energy. First Solar has plans to add 40 MW of additional capacity in the near future.

In 2011 alone, United States imported nearly 5 Billion USD worth of solar modules, 56% of which came from China, yet it only exported about 1 Billion USD worth of solar modules in the same year. PV exports have doubled from 442.7 million USD in 2006 to just over 1 Billion USD in 2011. According to Congressional research this rapid expansion in exports could be a sign of the maturity of the domestic market and increasing diversification.

The United States Federal Government has taken significant steps to promote solar power within its borders. “Advanced Energy Manufacturing Tax Credit” (MTC) is one specific example of legislation with this aim. Through the MTC, energy manufacturers involved in the construction of a new facility in the United States get a 30% tax credit on their investment. MTC had a cap of $2.3 Billion USD which was exhausted in 2010. Since the MTC has been so successful, the Obama Administration has proposed an extension of a further 5 Billion USD for the MTC program. Solar was also supported heavily through the executive branch of the Federal government in the form of Department of Energy Loan Guarantee Programs. The Department of Energy provided loan guarantees worth more than 16 billion USD for renewable energy projects, 13 billion USD of which went to solar.

In the United States about 120,000 people work in the solar industry according to Congressional research and employment in the solar industry has risen significantly since 2006 when only about 20,000 worked in the industry. Approximately half of this labour market relates to the installation of PV equipment and a further 20% in the manufacture of said equipment. The remaining 30% work in related fields including sales and distribution, project development, research and finance.

9

Geothermal

Contents

Strategic insight

1. Introduction

Geothermal Resources Potential

Geothermal energy comes from the natural heat of the Earth primarily due to the decay of the naturally radioactive isotopes of uranium, thorium and potassium. Because of the internal heat, the Earth's surface heat flow averages 82 mW/m^2 which amounts to a total heat of about 42 million megawatts. The total heat content of the Earth is of the order of 12.6×10^{24} MJ, and that of the crust, the order of 5.4×10^{21} MJ (Dickson and Fanelli, 2004). This huge number can be compared to the world electricity generation in 2007 of 7.1×10^{13} MJ (IEA, 2009). The thermal energy of the Earth is immense, but only a fraction of it can be utilised. So far utilisation of this energy has been limited to areas where geological conditions permit a carrier (water in the liquid or vapour phases) to 'transfer' the heat from deep hot zones to or near the surface, thus creating geothermal resources.

On average, the temperature of the Earth increases with depth, about 25–30˚C/km above the surface ambient temperature (called the geothermal gradient). Thus, assuming a conductive gradient, the temperature of the earth at 10 km would be over 300˚C. However, most geothermal exploration and use occurs where the gradient is higher, and thus where drilling is shallower and less costly. These shallow depth geothermal resources occur due to: 1) intrusion of molten rock (magma) from depth, bringing up great quantities of heat; 2) high surface heat flow, due to a thin crust and high temperature gradient; 3) ascent of groundwater that has circulated to depths of several kilometres and been heated due to the normal temperature gradient; 4) thermal blanketing or insulation of deep rocks by thick formation of such rocks as shale whose thermal conductivity is low; and 5) anomalous heating of shallow rock by decay of radioactive elements, perhaps augmented by thermal blanketing (Wright, 1998).

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. Geothermal production wells are commonly more than 2 km deep, but rarely much more than 3 km. With the average geothermal thermal gradient, a 1 km well in dry rock formations would have a bottom temperature near 40–45°C in many parts of the world (assuming a mean annual air temperature of 15°C) and a 3 km well one of 90–100°C.

Bertani (2003) found that, based on a compilation of estimates produced by a number of experts, the expected geothermal electricity potential ranges from a minimum of 35–70 GW_e to a maximum of 140 GW_e. The potential may be orders of magnitude higher, based on enhanced geothermal systems (EGS) technology. Stefansson (2005) concluded that the most likely value for the technical potential of geothermal resources suitable for electricity generation is 210 GW_e. Theoretical examinations indicate that the magnitude of hidden resource can be 5–10 times larger than the estimate of identified resources.

The magnitude of low-temperature geothermal resources in the world is about 140 EJ/yr of heat. For comparison, the world energy consumption is now about 420 EJ/yr.

It is considered possible to produce up to 8.3% of the total world electricity with geothermal resources, supplying 17% of the world population. Thirty nine countries (located mostly in Africa, Central/South America and the Pacific) can potentially produce 100% of their electricity using geothermal resources (Dauncey, 2001).

Types of Geothermal Resource

Geothermal resources are usually classified as shown in Fig. 9.1, modelled after White and Williams (1975) and ranging from the mean annual ambient temperature of around 20˚C to over 300˚C. In general, resources above 150˚C are used for electric power generation, although power has recently been generated at Chena Hot Springs Resort in Alaska using a 74˚C geothermal resource (Lund, 2006). Resources below 150˚C are usually used in direct-use projects for heating and cooling. Ambient temperatures in the 5–30˚C range can be used with geothermal (ground-source) heat pumps which provide both heating and cooling.

Figure 9.1
Geothermal resource types (Source: White and Williams, 1975)

Resource type	Temperature range (oC)
Convective hydrothermal resources	
Vapour dominated	≈240o
Hot-water dominated	20o-350o+
Other hydrothermal resources	
Sedimentary basin	20o-150o
Geopressured	90o-200o
Radiogenic	30o-150o
Hot rock resources	
Solidified (hot dry rock)	90o-650o
Part still molten (magma)	>600o

Convective hydrothermal resources can be found where the Earth’s heat is carried upward by convective circulation of naturally-occurring hot water or steam. Underlying some high-temperature convective hydrothermal resources are temperatures of 500º-1 000˚C from molten intrusions of recently solidified rocks. The lower temperature resources result from deep circulation of water along fractures.

Vapour dominated systems (‘dry steam’) produce steam from boiling of deep, saline waters in low permeability rocks. These reservoirs – few in number – The Geysers in northern California, Larderello in Italy and Matsukawa in Japan are being used to produce electricity.

Water-dominated systems (‘wet steam’) are based on ground water circulating at depth and ascending from permeable reservoirs with the same temperature over large volumes. There is typically an upflow zone at the centre of each convection cell, an outflow zone or plume of heated water moving laterally away from the centre of the system, and a downflow zone where recharge is taking place. On the surface they can appear as hot springs, fumaroles, geysers, travertine deposits, chemically altered rocks, or sometimes they are not noticeable at all (a blind resource).

Hot dry rock resources are defined as heat stored in rocks within about 10 km from the surface from where energy cannot be economically extracted by natural hot water or steam.

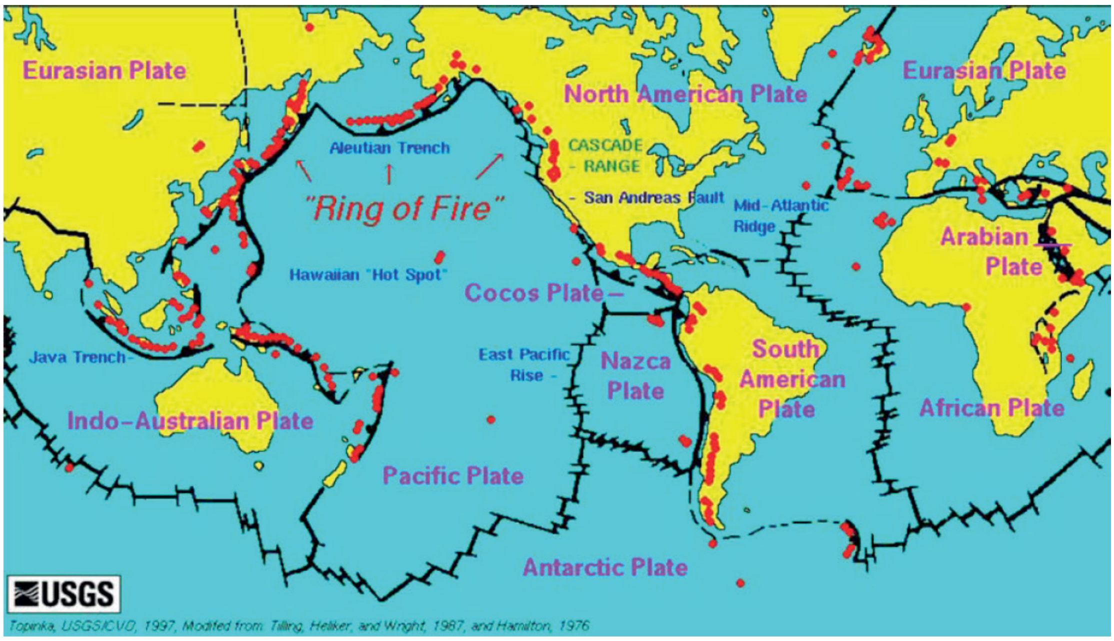
These hot rocks have few pores or fractures, and therefore, contain little water and little or no interconnected permeability. To extract the heat, new experimental technologies are being tested, including hydraulic fracturing under pressure, followed by cold water circulating down one well and producing hot water from a second well in a closed system.

Exploitable geothermal systems can be found in a number of geological environments. They can be broadly divided into two groups depending on whether they are related to young volcanoes and magmatic activity. High-temperature fields used for conventional power production are mostly confined to the former group, but geothermal fields utilised 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 geological conditions:

High-temperature fields (>180°C) are the fields where volcanic activity takes place mainly along so-called plate boundaries (Fig. 9.2). 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 and in many cases volcanic activity. Geothermal fields are very common on plate boundaries, as the crust is highly fractured and thus permeable to water, and other sources of heat. In such areas magmatic intrusions, sometimes with partly molten rock at temperatures above 1 000°C, situated at a few kilometres below the surface, heat the groundwater. The hot water has lower density than the surrounding cold groundwater and therefore it flows up towards the surface along fractures and other permeable structures;

Most of the plate boundaries are below sea level, but in cases where the volcanic activity has been intensive enough to build islands or where active plate boundaries transect continents, high-temperature geothermal fields are scattered along the boundaries. A spectacular example of this is the 'ring of fire' that surrounds the Pacific Ocean (the Pacific Plate) with intense volcanism and geothermal activity. Other examples are Iceland, which is located on the Mid-Atlantic Ridge plate boundary, the East African Rift Valley and 'hot spots' such as Hawaii and Yellowstone.

Figure 9.2
World map showing the lithospheric plate boundaries, dots = active volcanoes
Source: U.S. Geological Survey



Low-temperature fields (< 180°C) – 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 deep high-permeability rocks at hydrostatic pressure;
c. resources in high-porosity rocks at pressures greatly in excess of hydrostatic (i.e. 'geopressured');
d. resources in hot but dry (low-porosity) rock formations.

All these, with the exception of type c), can also be associated with volcanic activity. Types c) and d) are not commercially exploited as yet.

Type a) is probably the most common for warm springs in the world. These can occur in most rock types of all ages, but are most frequent 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.

Type b) is probably the most important type of geothermal resources 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. Geothermal resources of this type are rarely seen on the surface, but are commonly detected during deep drilling for oil and gas.

Enhanced Geothermal Systems (EGS) – the principle of EGS is simple: in the deep subsurface where temperatures are high enough for power generation (150–200°C) an extended fracture network is created and/or enlarged to act as new paths. Water from the deep wells and/or cold water from the surface is transported through this deep reservoir using injection and production wells, and recovered as steam/hot water. Injection and production wells as well as further surface installations complete the circulation system. The extracted heat can be used for district heating and/or for power generation.

A number of basic problems need to be solved for successful deployment of EGS systems, mainly that techniques need to be developed for creating, profiling, and operating the deep fracture system (by some means of remote sensing and control) that can be tailored to site-specific subsurface conditions. Some environmental issues, such as the chance of triggering seismicity and the availability of surface water, also need detailed investigation. There are several projects where targeted EGS demonstration is under way.

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 of 5–10 MW_e and rarely over 15 MW_e per well. It is well known 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 3.5–5 km, and at temperatures of 450–600°C.

Geothermal Utilisation and Characteristics

Electric Power Generation

Geothermal power is generated by using steam or a hydrocarbon vapour to turn a turbine-generator set to produce electricity. A vapour-dominated (dry steam) resource can be used directly, whereas a hot-water resource needs to be flashed by reducing the pressure to produce steam, normally in the 15–20% range. Some plants use double and triple flash to improve the efficiency, however in the case of triple flash it may be more efficient to use a bottoming cycle (a small binary plant using the waste water from the main plant). Low-temperature resources generally require the use of a secondary low boiling-point fluid (hydrocarbon) to generate the vapour, in a binary or Organic Rankine Cycle (ORC) plant.

Usually a wet or dry cooling tower is used to condense the vapour after it leaves the turbine to maximise the temperature and pressure drop between the incoming and outgoing vapour and thus increase the efficiency of the operation. However, dry cooling is often used in arid areas.

Binary plant technology is playing a very important role in the modern geothermal electricity market. The economics of electricity production are influenced by the drilling costs and resource development (a typical capital expenditure or Capex quota is 30% for reservoir and 70% plant). The electricity productivity per well is a function of reservoir fluid thermodynamic characteristics (phase and temperature).The higher the energy content of the reservoir fluid, the lesser the number of required wells and as a consequence the reservoir Capex quota is reduced. Single geothermal wells can produce from 1–5 MW_e, however, some producing as high as 30 MW_e have been reported. Binary plants on the reinjection stream could be a very effective way of producing cheap energy, because there would not be any additional pumping costs.

Direct Utilisation

The main advantage of using geothermal energy for direct use projects in the low- to intermediate-temperature range is that such resources are more widespread and exist in at least 80 countries at economic drilling depths. In addition, there are no conversion efficiency losses and projects can use conventional water-well drilling and off-the-shelf heating and cooling equipment (allowing for the temperature and chemistry of the fluid). Most projects can be on line in less than a year. Projects can be on a small scale, such as for an individual home, greenhouse or aquaculture pond, but can also be a large-scale commercial operation such as for district heating/cooling, or food and lumber drying.

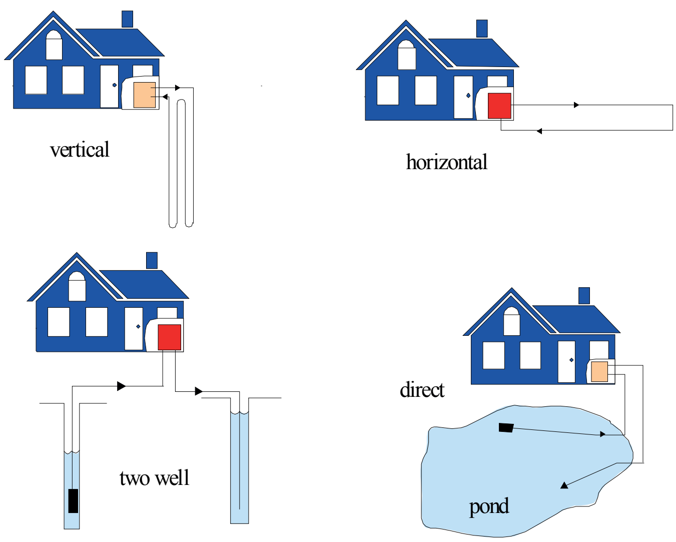
It is often necessary to isolate the geothermal fluid from the user side to prevent corrosion and scaling. Care must be taken to prevent oxygen from entering the system (geothermal water is normally oxygen-free), and dissolved gases and minerals such as boron and arsenic must be removed or isolated, as they are harmful to plants and animals. Hydrogen sulphide, even in low concentrations, will cause problems with copper and solder and is harmful to humans. On the other hand carbon dioxide, which often occurs in geothermal water, can be extracted and used for carbonated beverages or to enhance growth in greenhouses. The typical equipment for a direct-use system includes downhole and circulation pumps, heat exchangers (normally the plate type), transmission and distribution lines (normally insulated pipes), heat extraction equipment, peaking or back-up plants (usually fossil-fuel fired) to reduce the number of geothermal wells required, and fluid disposal systems (injection wells). Geothermal energy can usually meet 80–90% of the annual heating or cooling demand, yet only be sized for 50% of the peak load.

Geothermal Heat Pumps

Ground-source heat pumps (GHPs) use the relatively constant temperature of the earth to provide heating, cooling and domestic hot water for homes, schools, governmental and commercial buildings. A small amount of electricity input is required to run a compressor, however the energy output is in the order of four times this input. The technology is not new: Lord Kelvin developed the concept in 1852, which was then modified as a GHP by Robert Webber in Indianapolis in 1945. GHPs gained commercial recognition in the 1960s and 1970s. Europe began using this technology around 1970 and it now popular in the USA, Canada, Germany, Sweden, Switzerland, France and other western European countries.

GHPs come in two basic configurations: ground-coupled (closed loop) which are installed either horizontally or vertically, and groundwater (open loop) systems, which are installed in wells and lakes. The type chosen depends upon the soil and rock type at the installation, the land available and/or if a water well can be drilled economically or is already on site (Fig. 9.3)

Figure 9.3
Examples of common geothermal heat pump installations
Source: Lund, et al., 2004



In the ground-coupled system, a closed loop of high-density polyethylene pipe is placed either horizontally (1–2 m deep) or vertically (50–70 m deep) in the ground, and a water-antifreeze solution circulated through the pipe to either collect heat from the ground in the winter or reject heat to the ground in the summer (Rafferty, 2008). The open-loop system uses ground water or lake water directly in the heat exchanger and then discharges it into another well, into a stream or lake, or on the ground (say for irrigation), depending upon local regulations.

Figs. 9.4 and 9.5 show the operation of a typical geothermal heat pump in either heating or cooling mode. A desuperheater can be provided to use reject heat in the summer and some input heat in the winter for domestic hot water heating.

Figure 9.4

GHP in the cooling cycle

Source: Oklahoma State University

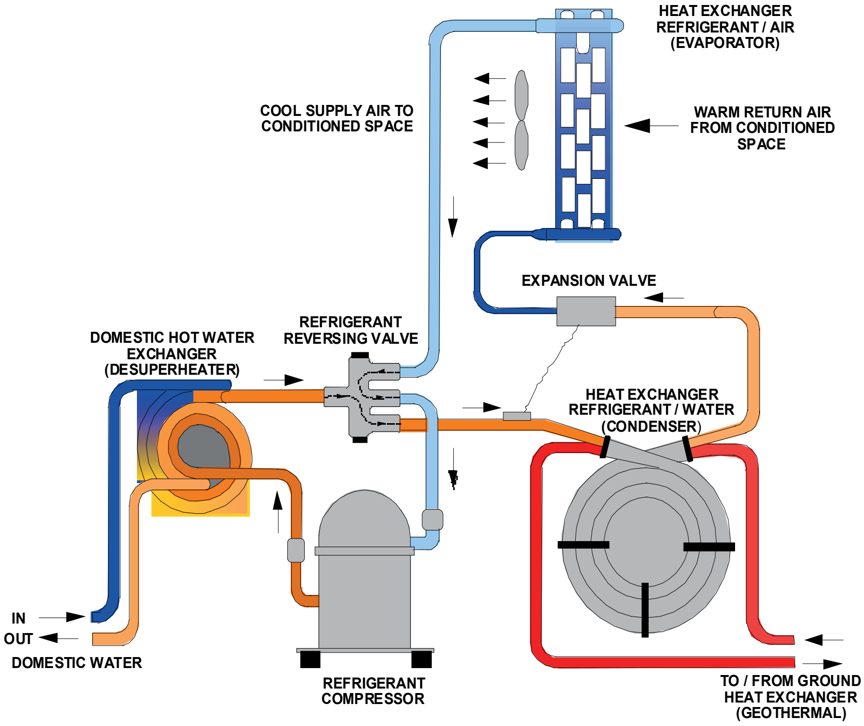
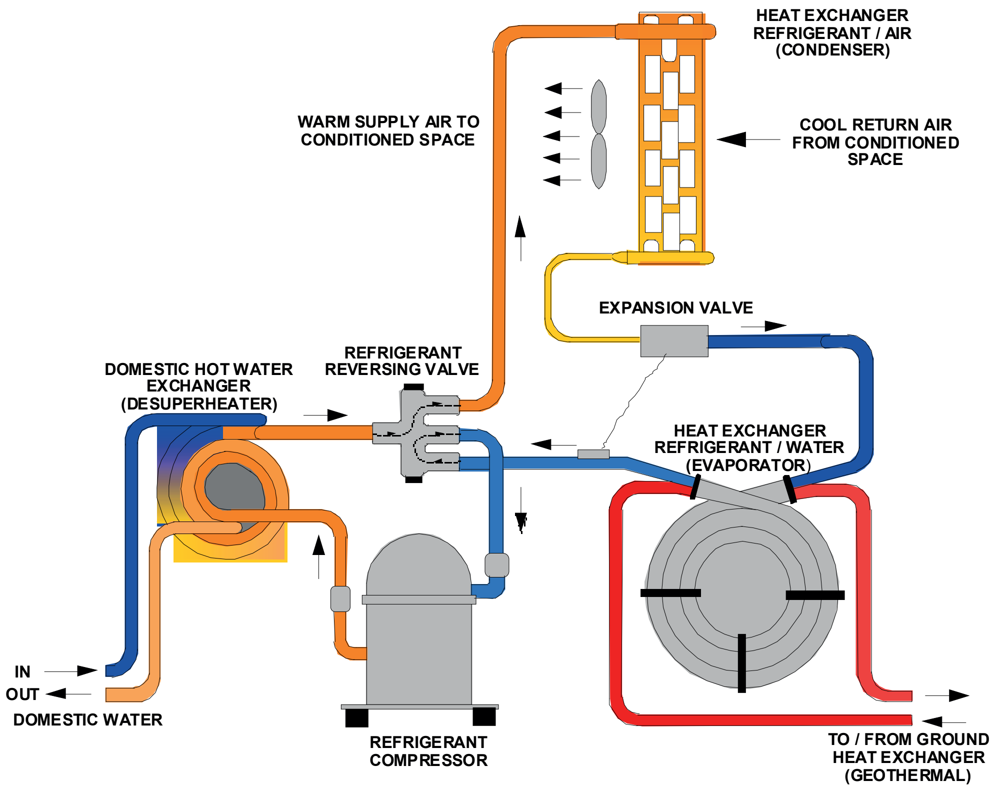


Figure 9.5
GHP in the heating cycle
Source: Oklahoma State University



Technical Potential

The main advantage of geothermal heating and power generation systems is that they are available 24 hours per day, 365 days a year and are only shut down for maintenance. Power generation systems typically have capacity factors of 95% (i.e. operate at nearly full capacity year round), whereas direct-use systems have a capacity factor around 25 to 30%, owing to heating not being required year round. Heat pump systems have operating capacities of around 10–20% in the heating mode and double this if the cooling mode is also included.

Within the direct utilisation sector of geothermal energy, geothermal heat pumps have world-wide application, as the shallow ground temperature is within their range anywhere in the world. Traditional direct use heating is limited to where the resource is available in economic depths and where climate justifies the demand.

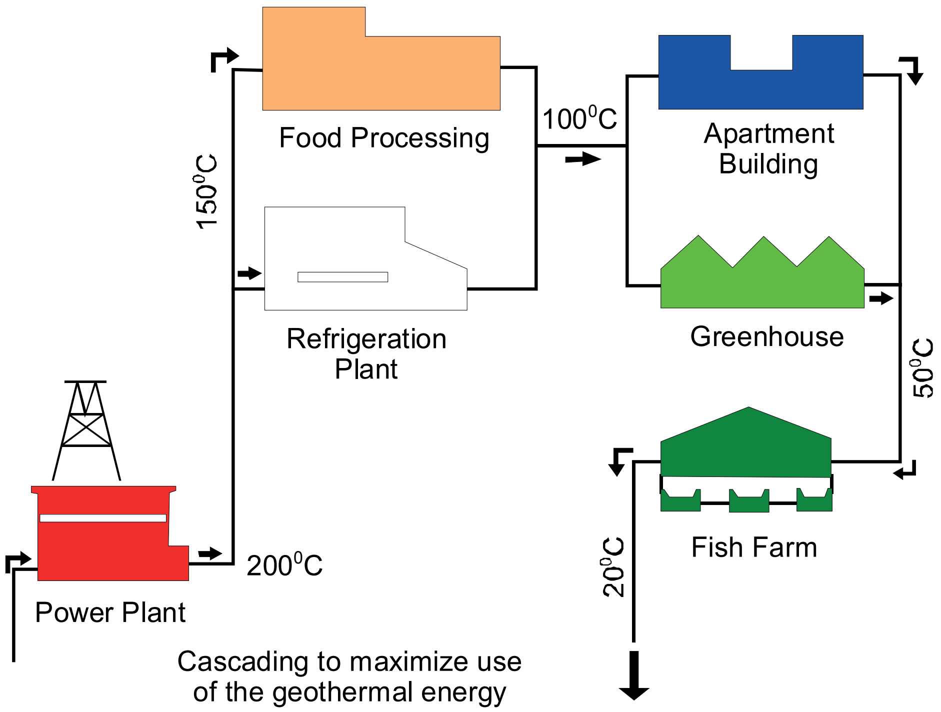
Power generation in the past has been limited by resources above 180°C. However, with recent advances in binary (Organic Rankine) cycle technology, lower-temperature fluids at around 100°C are being utilised, thus increasing the number of potential locations. Drilling depth, fluid quantity and quality, and temperature of the resource determine the economic viability of the project.

More recently, the use of combined heat and power plants has made low-temperature resources and deep drilling more economic. District heating using the spent water from a binary power plant can make a marginal project economic as has been done in Germany, Austria and Iceland. This is a form of cascading (Fig. 9.6), where the geothermal fluid is utilised at progressively lower temperature, thus maximising the energy extracted.

Figure 9.6

Example of cascaded geothermal resource for multiple uses

Source: Geo-Heat Centre



Summary of Current Geothermal Use

Table 9.1 is based on data for 2008 reported by WEC Member Committees for the present *Survey*, supplemented by information submitted to the World Geothermal Congress 2010.

Of the countries utilising their geothermal resource, almost all use it directly but only 24 use it for electricity generation.

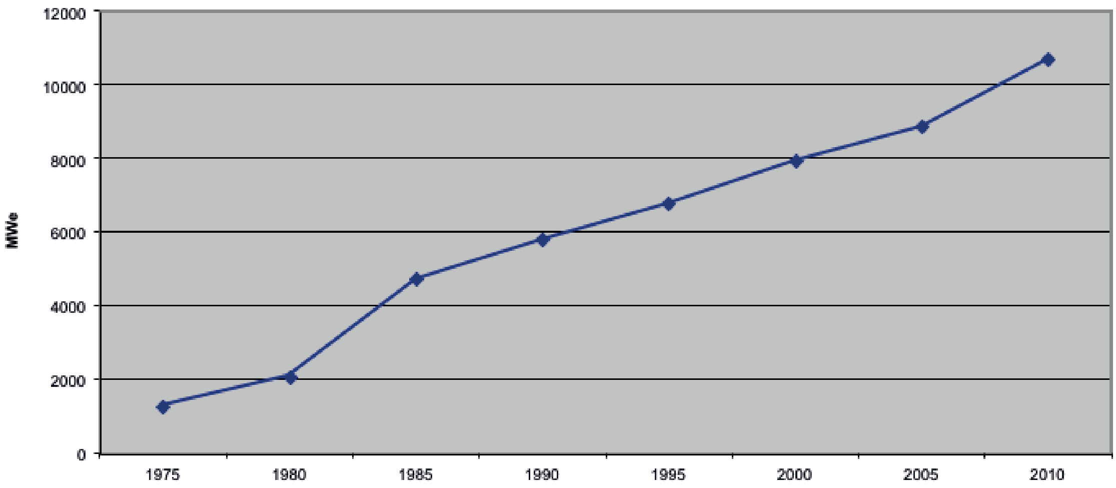
At end-2008, approximately 10 700 MW_e of geothermal electricity generating capacity was installed, producing over 63 000 GWh/yr. Installed capacity for direct heat utilisation amounted to about 50 000 MW_t, with an annual output of around 430 000 TJ (equivalent to about 120 000 GWh). The annual growth in energy output over the past five years has been 3.8% for electricity production and around 10% for direct use (including geothermal heat pumps). Energy produced by ground-source heat pumps alone has increased by 20% per annum over the same period. The low growth rate for electric power generation is primarily due to the low price for natural gas, the main competitor.

The data show that with electric power generation, each major continent has approximately the same percentage share of the installed capacity and energy produced, with the America's and Asia having over 75% of the total. Whereas, with the direct-use figures, the percentages drop significantly from installed capacity to energy use for the Americas (26.8 to 13.9%) due to the high percentage of geothermal heat pumps with low capacity factor for these units in the U.S. On the other hand, the percentages increased for the remainder of the world due to a lesser reliance on geothermal heat pumps and the greater number of operating hours per year for these units.

Geothermal Electric Power

Electric power has been produced from geothermal energy in 27 countries; however, Greece, Taiwan and Argentina have shut down their plants due to environmental and economic reasons. The worldwide installed capacity has the following distribution: 27% dry steam, 41% single flash, 20% double flash, 11% binary/combined cycle/hybrid, and 1% backpressure (Bertani, 2010).

Figure 9.7
Worldwide growth of installed geothermal generating capacity
Source: International Geothermal Association



Direct Utilisation (including geothermal heat pumps)

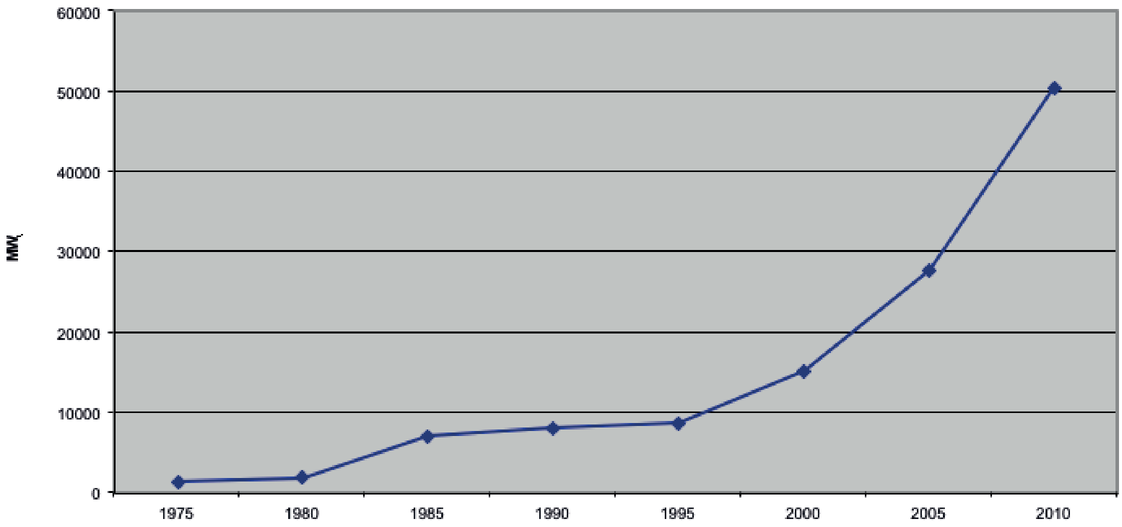
The world direct utilisation of geothermal energy is difficult to determine, as there are many diverse uses of the energy and these are sometimes small and located in remote areas. Finding someone or even a group of people in a country who are knowledgeable on all the direct uses is difficult. In addition, even if the use can be determined, the flow rates and temperatures are usually not known or reported, thus the capacity and energy use can only be estimated. This is especially true of geothermal waters used for swimming pools, bathing and balneology.

The total installed capacity, reported at the end of 2009, for the world's geothermal direct utilisation is 50 583 MW_t, almost a two-fold increase over the 2005 data, growing at a total rate of 12.3% annually. The total annual energy use is 438 071 TJ (121 696 GWh), a 60% increase over 2005, growing at a compound rate of 11.0% annually. Compared to ten years ago the capacity had been increasing by 12.8%/yr and the use by 8.7%/yr. Thus, it appears that the growth rate has increased slightly in recent years, despite the low cost of fossil fuels, economic downturns and other factors. It should, however, be noted that part of the growth from 2000 to the present is due, to a certain extent, to better reporting, and includes some geothermal countries that were missed in previous reports. The capacity factor is an indication of the amount of use during the year (i.e. a factor of 1.00 would indicate the system is used at a maximum the entire year, and 0.5 would indicate using the system for 4 380 equivalent full-load hours per year). The worldwide average for the capacity factor is 0.27, down from 0.31 five years ago and 0.40 ten years ago. This decrease is due to the increased used of geothermal heat pumps that have a worldwide capacity factor of 0.19 in the heating mode.

Figure 9.8

Worldwide growth of installed geothermal direct use capacity

Source: International Geothermal Association



The growing awareness and popularity of geothermal (ground-source) heat pumps had the most significant impact on the data. The annual energy use for these grew at a compound rate of 19.7% per year compared to five years ago, and 24.9% compared to ten years ago. The installed capacity grew 18.0% and 20.9% respectively. This is due, in part, to the ability of geothermal heat pumps to utilise groundwater or ground-coupled temperatures anywhere in the world.

The countries with the largest installed capacity were the USA, China, Sweden, Norway and Germany, accounting for about 63% of the installed capacity and the five countries with the largest annual energy use were: China, USA, Sweden, Turkey and Japan, accounting for 55% of the world use. Sweden, a new member of the 'top-five' obtained its position due to the country's increased use of geothermal heat pumps. However, if considered in terms of the country's land area or population, then the smaller countries dominate. The 'top-five' then include Netherlands, Switzerland, Iceland, Norway and Sweden (TJ/area), and Iceland, Norway, Sweden, Denmark and Switzerland (TJ/population). The largest increases in geothermal energy use (TJ/yr) over the past five years are in the United Kingdom, Netherlands, Korea (Republic), Norway and Iceland; and the largest increases in installed capacity (MW$_t$) are in the United Kingdom, Korea (Republic), Ireland, Spain and Netherlands, due mostly to the increased use of geothermal heat pumps.

In 1985, there were only 11 countries reporting an installed capacity of over 100 MW$_t$. By 1990, this number had increased to 14, by 1995 to 15, by 2000 to 23 and by 2005 to 33. At present there are 36 countries reporting 100 MW$_t$ or more. In addition, six new countries, compared to 2005, now report some geothermal direct utilisation.

Figure 9.9

Worldwide geothermal energy direct use

Source: International Geothermal Association

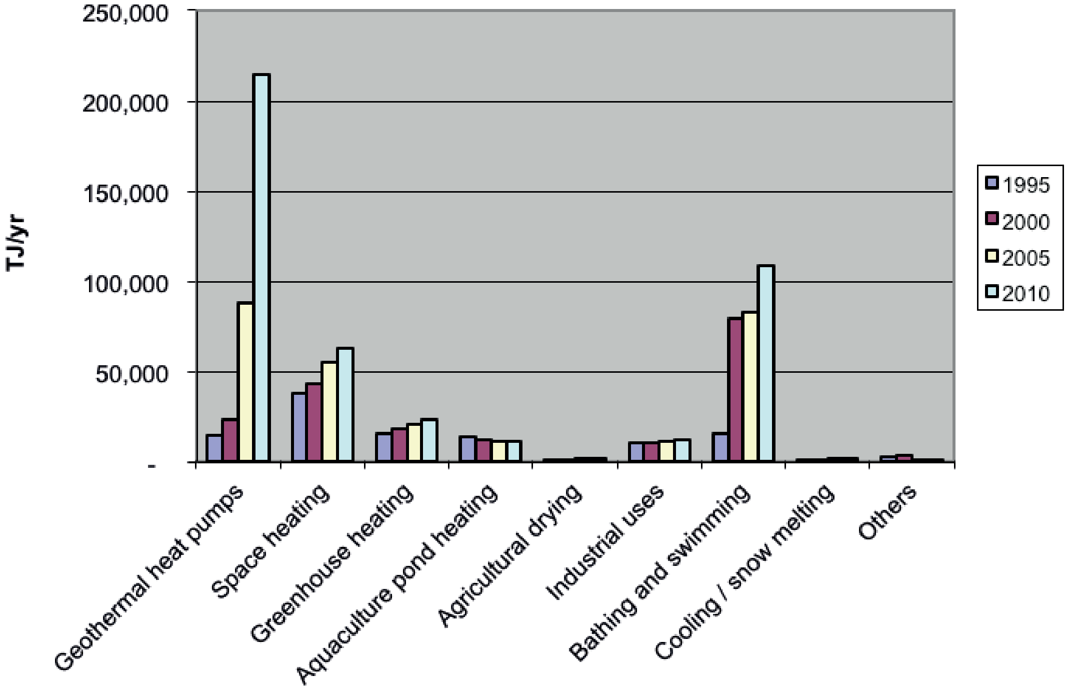
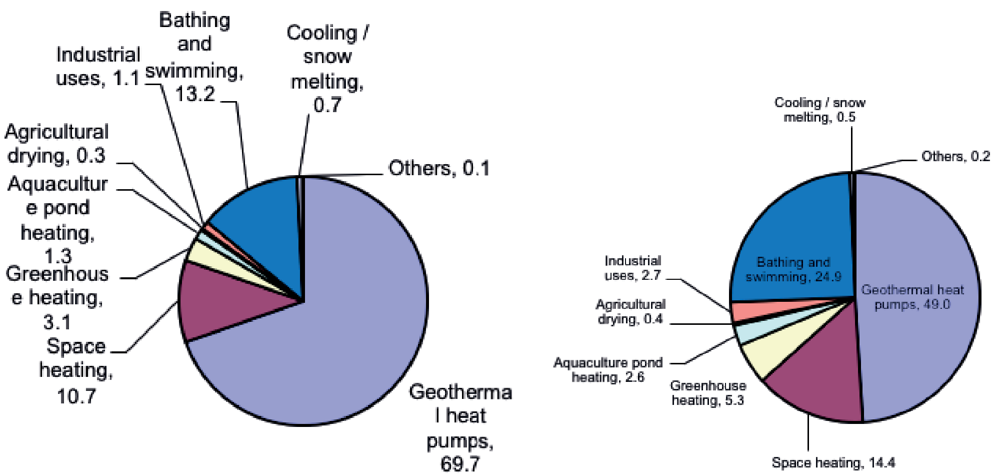


Figure 9.10

Categories of geothermal energy direct use in 2010: capacity (a), utilisation (b)

Source: International Geothermal Association



In Fig. 9.10 district heating is estimated at 78% of total space heating energy use and 82% of the installed capacity. Snow melting represents the majority of the cooling/snow melting figure.

Market Development

The factors that must be considered when assessing the viability of a geothermal project will vary from project to project (i.e. it is site-specific), especially between electricity generation and direct use. The economic factors that are common to all projects include supplying the fuel (energy) from the geothermal resource; the design and construction of the conversion facility and related surface equipment such as transformers and transmission lines for electricity generation plants, and pipelines and heat exchangers for district heating projects; and the operation and maintenance (O&M) of the equipment. Finally the market penetration and revenues generated from the sale of electricity or products produced from greenhouses, aquaculture facilities or industrial operations, minus the O&M costs, must be sufficient to meet or exceed the requirements of the financing package.

Financing is a critical factor in the economics of any project, and thus the potential for market penetration and development. For many new projects, the largest annual operating cost is the amortisation of the cost of capital, which can be as high as 75% of the annual operating expense for new geothermal district energy projects, with O&M at 15%, and ancillary energy provisions at 10% making up the balance (Bloomquist and Knapp, 2003). Unfortunately, geothermal projects, especially in the resource development stage, have a high risk of failure. Thus obtaining financing at reasonable rates (or even at all) can be difficult in the early stages of a project. Once the resource is proven, then financing is more certain and investors become easier to find..

Market development is highly dependent upon competition from other sources of electricity or from direct-use product supply (fish, vegetables, flowers, minerals, etc.). Remote areas, often off-grid, are excellent candidates for electrical energy. The availability of transmission lines can be critical and these are often lacking and expensive to construct over large distances. Direct-use projects must have a market and a transportation system to get the products to consumers economically. Unfortunately, geothermal resources that can be utilised are often remote, which may limit their development for commercial operations. However, on the positive side, with increasing fossil fuel prices and limitations on the production of greenhouse gases, development of geothermal energy has become more competitive as a renewable and ‘green’ energy resource.

Sustainability Issues

Geothermal energy is generally classified as a renewable resource, where ‘renewable’ describes a characteristic of the resource: the energy removed from the resource is continuously replaced by more energy on time scales similar to those required for energy removal (Stefansson, 2000). Consequently, geothermal production is not a ‘mining’ process. Geothermal energy can be used in a ‘sustainable’ manner, which means that the production system is able to sustain the production levels over long periods. The longevity of production can be secured and sustainable production achieved by using moderate production rates, which take into account the local resource characteristics (field size, natural recharge rate, etc.).

The production of geothermal fluid/heat continuously creates a hydraulic/heat sink in the reservoir. This leads to pressure and temperature gradients, which in turn – after end of production – generate fluid/heat inflow to re-establish the pre-production state. The regeneration of geothermal resources is a process which occurs over various time scales, depending on the type and size of the production system, the rate of extraction, and on the attributes of the resource.

Environmental Issues

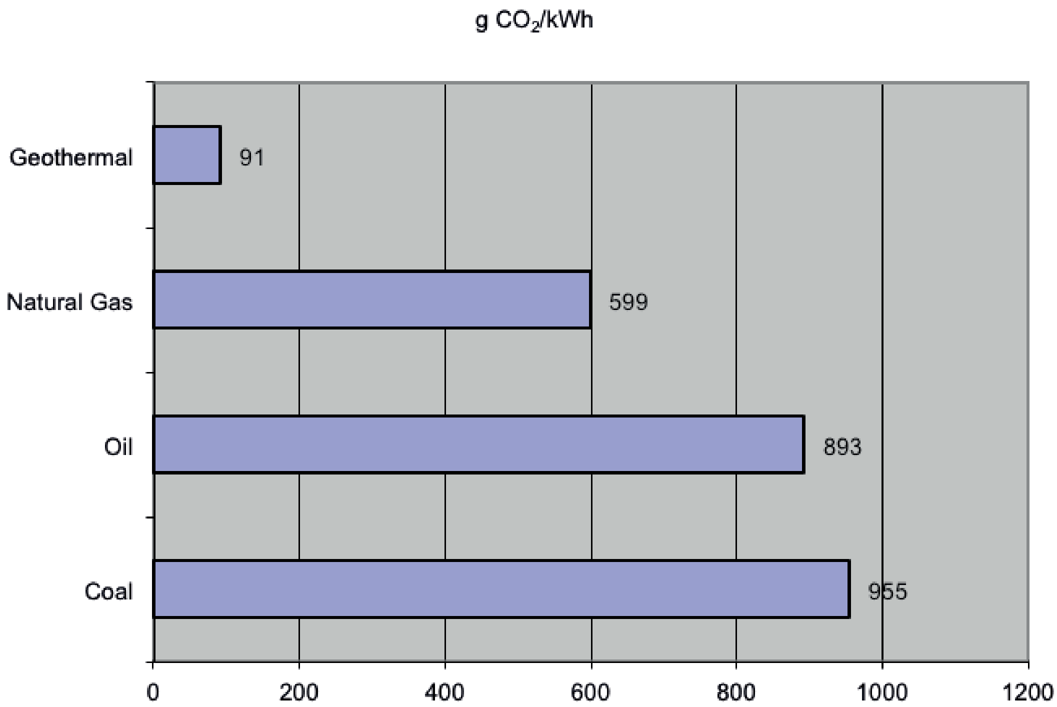
Geothermal fluids contain a variable quantity of gases, largely nitrogen and carbon dioxide, with some hydrogen sulphide and smaller proportions of ammonia, mercury, radon and boron. The amounts depend on the geological conditions of different fields. Most of the chemicals are concentrated in the disposal water which is routinely re-injected into drill holes and thus not released into the environment. The concentration of the gases is usually not harmful and they can be vented to the atmosphere. Removal of hydrogen sulphide released from geothermal power plants is mandatory in the USA and Italy.

The range of CO_2 emissions from high-temperature geothermal fields used for electricity production is variable, but much lower than that for fossil fuel plants.

Figure 9.11

Comparison of CO_2 emissions from electricity generation in the USA

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 cause scaling if it is released. In such cases the geothermal fluid is kept under 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 (zero CO_2 emission). GHP are environmentally benign and represent a large potential for reduction of CO_2 emissions.

2. Technical and economic considerations

Summary of Current Geothermal Use

Table 11.1 is based on electricity data for 2013 for the EGC Conference, supplemented by information submitted to the World Geothermal Congress 2010 for the Direct Heat utilization.

Of the countries utilising their geothermal resource, almost all use it directly but only 24 use it for electricity generation. At end-2012, approximately 11490 MWe of geothermal electricity generating capacity was installed, producing over 68630 GWh/yr. Installed capacity for direct heat utilisation amounted to about 50 000 MWt, with an annual output of around 430 000 TJ (equivalent to about 120 000 GWh).

The annual growth in energy output over the past five years has been 3.8% for electricity production and around 10% for direct use (including geothermal heat pumps). Energy produced by ground-source heat pumps alone has increased by 20% per annum over the same period. The low growth rate for electric power generation is primarily due to the low price for natural gas, the main competitor.

The data show that with electric power generation, each major continent has approximately the same percentage share of the installed capacity and energy produced, with the Americas and Asia having over 75% of the total. Whereas, with the direct-use figures, the percentages drop significantly from installed capacity to energy use for the Americas (26.8 to 13.9%) due to the high percentage of geothermal heat pumps with low capacity factor for these units in the U.S. On the other hand, the percentages increased for the remainder of the world due to a lesser reliance on geothermal heat pumps and the greater number of operating hours per year for these units.

Geothermal Electric Power

The worldwide installed capacity has the following distribution: 27% dry steam, 41% single flash, 20% double flash, 11% binary/combined cycle/hybrid, and 1% backpressure (Bertani, 2010).

Implementation Issues

The challenges to geothermal development are varied and include the following issues:

- resource identification and characterisation;
- economics, financial risks;
- development risks (i.e. proving the resource, drilling);
- competition by other forms of energy;
- environmental misconceptions;
- siting and permitting delays;
- transactional costs (i.e. high capital costs);
- transmission capacity (power) or market penetration (direct use);
- local population concerns;
- public perceptions and support;
- lack of knowledge of the benefits of development and utilisation.

Technical and Market Barriers

The major barrier to the exploitation of geothermal energy is the high financial risk in comparison not only with the use of natural gas but also with most other forms of renewable energy.

Development risks are high and prediction of the quality of a resource requires capital investment in drilling and well tests. A resource must also be close to an area of high demand. Those countries, e.g. France and Iceland, who have underwritten the risks at both the reservoir assessment and drilling stage, have been able to develop the resource more readily. Other countries, where geothermal energy plays a significant role in the total energy supply, such as Kenya, Philippines and several central American countries, have governmental support for development.

There is a lack of published technical, financial and legislative information for developers, particularly in comparing the experiences gained by others through various individual schemes.

Environmentally, geothermal schemes are relatively benign, but they generally produce a highly corrosive brine which may need special treatment and discharge consents. There is also a possibility of noxious gases, e.g. hydrogen sulphide, being emitted and developers must meet local environmental and planning requirements.

A combination of approaches can be used to overcome these barriers, including:

- educational, including training and outreach;
- technical improvements;
- economic incentives;
- government support.

Ruggero Bertani, John Lund
International Geothermal Association

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Global tables

Table 9.1
Geothermal energy: electricity generation and direct use at end-2011

	Electricity generation			Direct use		
	Installed capacity	Annual Output	Annual Capacity Factor	Installed capacity	Annual Output	Annual Capacity Factor
Country	MW	GWh	%	MW	TJ	%
Albania	8123.0	43.3	53.2	2.0	43.0	0.3
Algeria	0.0					
Argentina	30.0			149.9	609.4	
Australia	1.1	0.7	53.2	129.0	1314.3	
Austria	0.9	1.1		662.0	8107.0	
Brazil				360.0		
Bulgaria				98.3	1370.1	
Canada	0.0			1045.0	5112.0	
Chile	0.0			9.1	131.8	
China	24.2	125.0		8898.0	75348.3	
Costa Rica	166.0	1131.0				
Croatia				114.0	557.0	
Czech Republic	0.0			4.5	90.0	
Denmark				200.0	2500.0	
Ecuador				5.0		
El Salvador	204.0	1422.0				
Ethiopia	7.3	10.0				
France	18.3	14.0		1345.0	12949.0	
Germany	7.3	18.8		3485.4	12764.5	
Greece	0.0			134.6	937.8	
Guatemala	52.0	289.0		2.3	56.5	
Hong Kong	24.0					
Hungary	0.0			654.6	9767.0	
Iceland	665.0	4465.0		2002.9	24621.4	
Indonesia	1197.0	9321.0				
Israel				23.4	692.0	
Italy	772.0	5754.0		1000.0	12599.5	
Japan	537.7	2632.0		2099.5	25697.9	
Kenya	169.0	1430.0		16.0	126.6	
Korea (Republic)				105.4	43.0	
Lithuania				48.1	411.5	
Mexico	886.6	6502.0		155.8	4022.7	
Netherlands	0.0			1410.3	10699.4	

New Zealand	792.0	5550.0		393.0	9552.0
Nicaragua	82.0	289.8			
Norway				1000.0	
Philippines	1904.0	10311.0		3.3	39.6
Poland	0.0			281.0	1501.0
Portugal	30.0	210.0		28.1	420.0
Romania	0.0			173.6	1520.2
Russian Federation	82.0	441.0		308.2	6143.5
Serbia				119.0	3244.0
Slovakia				132.2	3067.2
Spain	0.0			120.0	
Sweden				4460.0	45301.0
Switzerland	0.0			1060.6	8799.0
Thailand	0.3	2.0		2.5	79.1
Turkey	114.2	616.7		2084.0	36885.9
United Kingdom	0.0			186.6	849.7
United States of America	3101.6	15009.0		12611.5	56551.8

Country notes

The Country Notes on Geothermal Energy have been compiled by the Editors with input from the WEC Member Committees. A wide range of sources have been consulted, including national, international and governmental publications/web sites and other publicly available information. Use has also been made of direct personal contacts.

N.B. All direct-use data for Geothermal includes figures for heat pump technology.

Albania

	Electricity generation
Installed capacity MWe	
Annual output GWh	
Annual capacity factor	
	Direct use
Installed capacity, MWt	12
Annual output TJ	41
Annual capacity factor	

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.

Geothermal resources are widely available in Albania. Similar to neighbouring countries, the potential of geothermal heat is vast. There are many thermal springs of low enthalpy with a maximal temperature of up to 80°C as well as many wells (abandoned gas or oil) in Albania, which represent a potential for geothermal energy.

The geothermal field is characterized by relatively low values of temperature. The temperature at a depth of 100 meters varies from 8 to 20°C. The highest temperatures (up to 68°C) at 3000 meters depth have been measured in the plane regions of western Albania. The temperature is 105.8°C at 6000 meters depths. The lowest temperature values have been found in the mountainous regions. There are many thermal springs and wells of low enthalpy. Their water have temperatures up to 65.5°C. The thermal springs and wells are located in three areas: the geothermic area of Kruje, Ardenica and Peshkopii.

Algeria

	Electricity generation
Installed capacity MWe	
Annual output GWh	
Annual capacity factor	
	Direct use
Installed capacity, MWt	56
Annual output TJ	1723
Annual capacity factor	

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.

The most widely recognised use of geothermal springs is for balneotherapy. These hot springs are mainly located in the northern part of the country, used by about ten public resorts.

During the last few years, a significant interest has been shown for alternative uses of geothermal energy. Three sites have been selected for geothermal aquaculture projects. Currently, fish farms in Ghardaia and Ouargla are using the Albian geothermal water of the Sahara to produce about 1,500 tonnes/yr of Tilapia fish. A third site at Ain Skhouna, located near Saida produced 200 tonnes of Tilapia during 2008.

A small geothermal heat pump project has also been started in this region. The heat pump is a reverse one, used for heating and cooling 12 classrooms, the library and the restaurant of a primary school. Hammam Sidi Aissa geothermal water (46°C) is used for this purpose. A similar project is planned to be opened at Khenchla (North East of Algeria). These various applications of geothermal water are: 1.4 MWt and 45.1 TJ/yr for individual space heating; 9.8 MWt and 308 TJ/yr for fish farming; 44.27 MWt and 1,368.65 TJ/yr for bathing and swimming; 0.17 MWT and 1.38 TJ/yr for geothermal heat pumps.

Argentina

	Direct use
Installed capacity, MWt	307.5
Annual output TJ	3906.7
Annual capacity factor	0.30

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. 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.

Direct use of geothermal heat is widespread in Argentina. The total capacity of 150 MW_t – installed at 70 different locations – was mainly used for bathing and swimming but also with some applications in fish farming, greenhouse and soil heating, individual space heating and snow melting.

Australia

Within the last five years 11 new projects were started and are now being explored for direct-use. These projects are being considered for recreational therapeutic facilities and to supply drinking water to nearby towns.

	Electricity generation
Installed capacity MWe	1.1
Annual output GWh	0.7
Annual capacity factor	53.2
	Direct use
Installed capacity, MWt	129
Annual output TJ	1314.3

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.

The Australian geothermal resource can be classified into three categories: Hot Sedimentary Aquifers (HSA); Hot Rock (HR), including Hot Dry Rocks (HDR), and Hot Fractured Rocks and Direct Use (HFR). The first two categories have the potential for electricity generation. However, the sole use of geothermal power for electricity generation in Australia is the 120 kW (gross) Birdsville plant in Queensland. For the past decade it has supplied the town's night time electricity requirements and generally during the winter. When the geothermal plant is able to satisfy demand, an automatic switching system shuts down the fossil-fuel generated electricity system.

It has been estimated that Australia's very significant HDR resource is sufficient to generate the country's electricity requirement for centuries to come.

The total expected geothermal EGS installed capacity for 2020 is about 100 MW.

Austria

	Electricity generation
Installed capacity MWe	0.9
Annual output GWh	1

	Direct use
Installed capacity, MWt	662
Annual output TJ	8 107

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 land-owner and this can be highly problematical when deviated drilling is necessary.

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.

Seven deep boreholes were drilled in the country recently, all of which were used to supply heat for balneological purposes. No other geothermal projects were undertaken in Austria since 2005 due to lack of public support and low feed-in tariffs for electric power. However, the number of ground source heat pumps has shown a steady increase with the estimated number of units at 50,000 having a capacity of 600 MWt and producing 800 GWh/yr. As in most countries the data on geothermal heat pumps are hard to obtain as only groundwater wells are documented with the authorities. Future projects are expected in the Vienna basin near the capital and in the Austrian Molasse Basin. Geothermal heat pumps are expected to increase with more than 50% of the new family houses to have units installed.

Brazil

	Electricity generation
	Direct use
Installed capacity, MWt	360
Annual output TJ	
Annual capacity factor	

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.

In 2005 it was reported that the installed capacity (some 360 MW_t) was 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) could 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 totaled 16 MW_t, the PIS, 343 MW_t and the TDB, 3 MW_t, although the PIS element was not being used industrially, but for recreational purposes.

Bulgaria

	Electricity generation
Installed capacity MWe	
Annual output GWh	
Annual capacity factor	
Direct use	
Installed capacity, MWt	98.3
Annual output TJ	1370.1
Annual capacity factor	

The number of hydrothermal sources in Bulgaria has been estimated at around 150 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°C. Only about 4% of the total capacity has been found to have water hotter than 90°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. The annual average production is around 428 GWh.

Bulgaria has a rich geothermal water supply within the temperature range of 20 to 100oC with the main geothermal activity concentrated in the southern part of the country due to the higher water temperature and low water salinity. The main geothermal direct-use in the country is for balneology (prevention, treatment and rehabilitation, bathing and swimming pools), space heating and air-conditioning, greenhouse heating, geothermal heat pumps, direct thermal water supply, bottling of potable water and soft drinks and for unspecified industrial use. The cultivation of microalgae and production of iodine paste and methane extraction are some of the processes no longer in place.

Canada

	Electricity generation
Installed capacity MWe	
Annual output GWh	
Annual capacity factor	
	Direct use
Installed capacity, MWt	1045
Annual output TJ	5112
Annual capacity factor	

The geography of Canada does not easily lend itself to electricity generated from geothermal resources. However, since the late 1970s exploratory work has been ongoing at a volcanic complex, Mt. Meager in British Columbia. The site may have potential development capacity of 100 MW or greater, but this has not yet been verified.

Ground source heat pumps can be installed almost anywhere in Canada and in total could theoretically meet the entire heating and cooling need of the country's building stock.

Since 2005 Canada has experienced a major transformation of the ground source heat pump industry. Led by the Canadian GeoExchange Coalition (CGC) and supported by

Natural Resources Canada, more than 3 000 industry professionals have been trained to Canadian standards and more than 800 have received their installer or residential designer accreditation. The CGC has also certified thousands of residential installations.

In recent years Canada has progressively increased the usage of heat pump technology. It is estimated that up to 50,000 residential and 5,000 commercial systems are currently installed. The cost of installing these units, especially in building retrofits, is often prohibited for the average consumer; however, federal and local subsidies have contributed towards the costs. The growth rate is estimated at 13% per year, with recent rates being as high as 50%.

Heat pump technology has also been used in abandoned mines, starting as early as 1989 in the Springhill Mine of Nova Scotia where the heating and cooling provides savings estimated C$45,000/yr in energy costs. The City of Yellowknife in the Northwest Territories commissioned a study in 2007 to use water from an abandoned gold mine with a heat pump to provide district heating to the community, saving an estimated C$13 million/yr.

Chile

	Electricity generation
Installed capacity MWe	
Annual output GWh	
Annual capacity factor	
	Direct use
Installed capacity, MWt	9.1
Annual output TJ	131.8
Annual capacity factor	

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.

Geothermal energy in Chile is mainly used for recreational purposes. Current use in spa and swimming pools accounts for all the capacity. However, there are many private thermal spas and resorts in the geothermal area, for which quantitative information regarding their use of geothermal resources is not available. In some spas, shallow wells have been drilled to obtain hot water, while in others hot water is collected rudimentary and piped to the buildings pools, through shallow drains and plastic hoses.

China

	Electricity generation
Installed capacity MWe	24.1
Annual output GWh	125
Annual capacity factor	
	Direct use
Installed capacity, MWt	8 898
Annual output TJ	75 348
Annual capacity factor	

With its move to a fast-growing market economy and increasing environmental concerns, the utilisation of geothermal energy in China continues to increase, but not with the same rapidity as other renewable energies.

Studies have identified more than 3 000 hot springs and more than 300 geothermal 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 southeast, the North China Basin, Songliao Basin, Jianghan Basin, Weihe Basin, etc.

Historically, the primary development has been in geothermal energy used directly. Approximately half of installed capacity is used for bathing and swimming, with the next largest sector being district heating. Other uses include agricultural drying, fish farming, greenhouse heating and industrial process heat.

The utilisation of geothermal heat pumps (GHP) has grown dramatically in recent years. GHP applications were used extensively in the 2008 Beijing Olympic Games venues. By end-2009 installed capacity of GHP was some 5.2 GW_t, considerably higher than the installed capacity for other direct uses.

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). At present the only operational power plant is at Yangbajain (Tibet). Capacity is 24.18 MW_e, generating about 125 GWh annually.

Bathing, agriculture, and fish farming have continued to be major uses for geothermal fluids.

Colombia

	Electricity generation
Installed capacity MWe	
Annual output GWh	
Annual capacity factor	
	Direct use
Installed capacity, MWt	
Annual output TJ	
Annual capacity factor	

Colombia is located on the Pacific Ring of Fire, which provides positive anomalies in respect of the geothermal resource, exemplified by numerous volcanoes and high-temperature hydrothermal systems, associated with magmatic heat sources.

Although exploratory work is being conducted, there has been no actual utilisation yet of the high temperature resource.

Unassociated with magmatic heat, there are low- to medium- temperature hydrothermal sources, evidenced by warm springs throughout the country. Currently, the small use of geothermal heat is confined to bathing and swimming (including balneology).

In the central cordillera of the Andes, is located Nevado del Ruiz volcano, surrounded by a large area of surface and keeping in the ground wealth of an increasingly more important and vital energy.

Costa Rica

	Electricity generation
Installed capacity MWe	166
Annual output GWh	1131
Annual capacity factor	
	Direct use
Installed capacity, MWt	
Annual output TJ	
Annual capacity factor	

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 northwestern part of the country and have been studied in detail.

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.

Future development of the country's geothermal resource, for instance the construction of Las Pailas II or Borinquen I will depend on feasibility studies, scheduled for 2011.

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

	Electricity generation
Installed capacity MWe	
Annual output GWh	
Annual capacity factor	
	Direct use
Installed capacity, MWt	114
Annual output TJ	557
Annual capacity factor	

The considerable Croatian geothermal resource is located in two large geological formations: the Panonian Basin to the north and east, and the Dinarides Belt in the south of the country. These two geologically different regions have significant differences in potential. At the present time usage of the resource is increasing, but it is still at a very low level.

The direct utilization of geothermal nergy in the Croatia is mainly for heating swimming pools and spas along within recreational centers, as well as space heating. There are 20 spas and five geothermal fields above 100oC that are using geothermal energy. The five high temperature geothermal fields are being considered for combine heat and electrical energy production.

Czech Republic

	Electricity generation
Installed capacity MWe	
Annual output GWh	
Annual capacity factor	
	Direct use
Installed capacity, MWt	4.5
Annual output TJ	90
Annual capacity factor	

Geothermal energy has been little used, and then only directly (in spas and swimming pools), for over a century. At the present time only one geothermal source is being utilised as a source of power for installed heat pumps. However, in order to meet the EU target of 13% reliance on renewable energy by 2020, utilisation of the resource will likely play a part, albeit small.

Within the Czech Republic about 60 sites have been identified with a theoretical electricity potential of 250 MW_e and a heat supply capacity of about 2 000 MW_t. The resulting electricity generation has been estimated to be some 2 TWh and usable heat, 4 TWh. It is considered that, if successful, further exploration could lead to higher production.

At the beginning of 2009 ČEZ, the country's largest power company, issued a tender for a survey to determine the feasibility of constructing a geothermal power plant in Liberec, north Bohemia.

The direct use of thermal water in spas and swimming pools dates back several hundred years. There are 11 major spas and thermal springs in the Czech Republic, the most famous being Karlovy Vary and Marianske Lazně.

More than 10,000 geothermal heat pumps have been installed, at an average capacity of 20 kW. Using a COP of 3.5 and 2,200 full load operating hours per year, the annual energy use is then estimated at 832 TJ/yr. The estimated capacity for the spas is 4.5 MWt, with an energy use of 90 TJ/yr.

Denmark

	Electricity generation
Installed capacity MWe	
Annual output GWh	
Annual capacity factor	
	Direct use
Installed capacity, MWt	200
Annual output TJ	2 500
Annual capacity factor	

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.

Research has shown that the estimated geothermal resource in the area surrounding Copenhagen represents an output of 60 000 PJ.

Temperatures in Denmark are of low-enthalpy with no pronounced temperature anomalies, with normal gradients of 25 to 30oC/km. Two large district heating plants using heat pumps have been built in the country.

The first was established in 1984 at Thisted producing 44oC saline water at 200 m3/h from 1,250 m depth resulting in 7 MWt of installed capacity. The second in Copenhagen started in 2005, uses 73oC saline water at 235 m3/h from 2,560 m depth resulting in an installed capacity of 14 MWt. A number of small heat pump projects have been installed, estimated at 20,000 units in a vertical configuration with a capacity and annual energy use of 160 MWt and 1,700 TJ/yr. Ground water is also being used for cooling and industrial locations.

Ecuador

	Electricity generation
Installed capacity MWe	
Annual output GWh	
Annual capacity factor	
	Direct use
Installed capacity, MWt	5
Annual output TJ	
Annual capacity factor	

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.

Ecuador has a very large geothermal potential (it is estimated that it could arrive up to 500 MW) but it has not yet been exploited. It is estimated that the direct usage of geothermal heat can contribute to the development of rural areas and highly contribute to a diminution of poverty.

Geographical Areas With Major Potential: Since the first investigations were conducted, the following areas, that present excellent potential for geothermal usage, were individuated. Tufiño-Chiles Cerro Negro (binational project Ecuador-Colombia), Chachimbiro (Imbabura Province), Chalupas (Cotopaxi Province), in addition to 17 other individuated areas with potential such as Napo-Pichincha, Cuenca, Chalpatan, Pululahua. From these areas, the potential is estimated at approximately 534 MW of energy. Several regions in the country remain un-explored for geothermal resources, namely in the sedimentary basins in the Costa, in the Oriental sedimentary basins and in the Galapagos archipelago. The Andes form the backbone of the country. In the Northern half of the two mountain ranges that constitute the Andes (the Western and Eastern Cordilleras) there exists a well developed arch from Quaternary age that consists of more than 50 volcanoes, of which 30 are active. Recently, in November 2011, the Volcano Tungurahua, situated in the Eastern Cordillera, erupted. The

Southern part of the Andes, according to a study from the Department of Geothermal Power of the Escuela Politécnica Nacional, reports only extinct volcanic activity. The strongest volcanic activity can be witnessed in the Western-most islands, Fernandina, Isabela and Roca Redonda.

El Salvador

	Electricity generation
Installed capacity MWe	204
Annual output GWh	1422
Annual capacity factor	
	Direct use
Installed capacity, MWt	
Annual output TJ	
Annual capacity factor	

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 although a potential exists for the direct use of geothermal in drying grains and fruit.

Of the 204.4 MW_e of geothermal capacity currently installed in El Salvador (95 MW_e at Ahuachapán, and 109.4 MW_e at Berlín), 183.8 MW_e is reported to be actually available (80 MW_e at Ahuachapán and 103.8 MW_e at Berlín).

Ethiopia

	Electricity generation
Installed capacity MWe	7.3
Annual output GWh	10
Annual capacity factor	
	Direct use
Installed capacity, MWt	
Annual output TJ	
Annual capacity factor	

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 – in the Main Ethiopian Rift and in the Afar depression. Exploration that began in 1969 has, to date, revealed a potential that could possibly generate more than 5 000 MW_e of electricity. Of the approximately 120 localities that are believed to have independent heating and circulation systems, about two dozen are judged to have potential for high enthalpy resource development, including for electricity generation. A much larger number are capable of being used directly for horticulture, animal breeding, aquaculture, agro-industry, health and recreation, mineral water bottling, mineral extraction, space cooling and heating etc.

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. Although geothermal is similar to, for example, hydro in that an installation requires a high initial investment cost, it has the advantage of having a possibly greater than 90% availability factor, perhaps double that of others of similar installed capacity. Recognising this, the Government has taken steps to implement changes to the legal and institutional framework in order for geothermal resources to compete with conventional energy systems and is committed to investigate and develop the country's geothermal potential.

Geothermal exploration work in Ethiopia started in 1969 and continues up to now. Possible resource areas have been defined within the Ethiopian sector of the East African Rift system and the Afar triangle.

France

	Electricity generation
Installed capacity MWe	18.3
Annual output GWh	14.0
Annual capacity factor	
	Direct use
Installed capacity, MWt	1 345
Annual output TJ	12 929
Annual capacity factor	

Low-enthalpy geothermal resources in metropolitan France 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.

The French WEC Member Committee reports the plan includes a 2020 objective of producing 2.4 Mtoe of geothermal heat and equipping 2 million households with heat pumps.

The development of geothermal resources in the country has seen several phases: after a major development phase based on low enthalpy resources from sedimentary basins at the beginning of the 1980s; followed by a period of withdrawal during the 1990s with very little new activity; then more recently by a revival of activity of all kinds, based on a policy by the government for energy management and development, especially of renewable energy (French Energy Law in 2005 and the large consulting process "Grenelle de l'environnement" in 2007).

Germany

	Electricity generation
Installed capacity MWe	7.3
Annual output GWh	18.8
Annual capacity factor	
	Direct use
Installed capacity, MWt	2 485
Annual output TJ	12 764
Annual capacity factor	

Germany's hydrothermal resources, down to a depth of 5 000 m, are located in the North German Basin, the Molasse Basin in the south of the country and the Upper Rheingraben.

The hot dry rock (HDR) resource, at a depth of between 3 000 and 7 000 m, is thought to exist in the Crystalline Basement in the middle and south of the country, the Crystalline Basement in the Upper Rheingraben and the Rotliegend volcanites in the North German Basin.

An evaluation of the maximum recoverable potential for electricity generation from HDR technology has been estimated at 8 620 EJ and 90 EJ from hydrothermal resources.

The first German geothermal power plant (230kW$_e$) was inaugurated at Neustadt-Glewe in November 2003 to provide electricity for 500 households and a second 3 MW$_e$ plant began operating in Landau in 2007. A third 3.4 MW$_e$ plant at Unterhaching first generated heat during 2007 and then electricity in late 2008.

Most of the district heating plants are located in the Northern German Basin, the Molasse Basin in Southern Germany, or along the Upper Rhine Graben. Two geothermal power plants at Neustadt-Glewe and Unterhaching also provide water for district heating.

In addition to these large installations, there are numerous small- and medium-size geothermal heat pump units located throughout the country. Under the prevailing economic and political conditions, multiple or cascaded uses are employed to help improve the economic efficiency of the direct use. For this reason many installations combine district or space heating with greenhouses and thermal spas. No numbers are given for greenhouse heating.

Greece

	Electricity generation
Installed capacity MWe	
Annual output GWh	
Annual capacity factor	
	Direct use
Installed capacity, MWt	134.6
Annual output TJ	937.8
Annual capacity factor	0.30

Greece possesses both high- and low-enthalpy geothermal fields. The former occurs in the islands of Milos, Santorini, Nisyros, etc. located in the South Aegean volcanic arc. The latter are situated in the plains of Macedonia and Thrace and in association with the country's hot springs. At the present time the geothermal resource is not harnessed for electricity generation.

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 135 MW$_t$ for space heating, greenhouse and soil heating, bathing and spas, industrial uses, fish farming, cultivation of spiroulina and geothermal heat pumps.

Although the number of heat pump installations in Greece does not equate with some other European countries, nevertheless there has been a strong rate of growth in recent years.

The first half of the present decade was characterized by a diversification of direct applications with new uses such as aquaculture, spirulina production, outdoor pool heating, water desalination and fruit and vegetable dehydration. However, in the past few years there has been a rapid expansion of geothermal heat pumps.

Approximately 21 ha of greenhouses are heated, mainly for vegetable and cut flower growing, with 27 greenhouse units in the country run by 21 operators. Some soil heating, especially for asparagus, has increased significantly and is now 17 ha. There are more than 60 thermal spas and bathing centers in operation. A tomato dehydration unit has been operating since 2001 producing more than 1,000 kg of dehydrated tomatoes per day. Geothermal water is used for frost protection for a number of aquaculture ponds during the winter. Approximately 350 geothermal heat pump applications are located in the country with about 65% being of the open loop configuration.

Guadeloupe

	Electricity generation
Installed capacity MWe	
Annual output GWh	
Annual capacity factor	
	Direct use
Installed capacity, MWt	16
Annual output TJ	
Annual capacity factor	

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.

Geothermal electricity is not available on the mainland, but only in the Caribbean islands it can reach up to 20% of electricity needs.

The high enthalpy utilization for electricity production in France is only in the French Overseas Department, at Bouillante on Guadeloupe island (Geothermie Bouillante). Its exploitation started in 1984, and a second unit in 2004 has been commissioned. The reservoir temperature is 250°C at shallow depth. The total capacity of 15 MW, not increased since 2005, produces 95 GWh, corresponding to 8% of the local consumption. The activity for the third unit of 20 MW is ongoing. The final target will reach 20% of geothermal contribution to the electricity needs.

Guatemala

	Electricity generation
Installed capacity MWe	52
Annual output GWh	289
Annual capacity factor	
	Direct use
Installed capacity, MWt	2.3
Annual output TJ	56.5
Annual capacity factor	

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.

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.

During 2007, a 20 MW_e binary plant was commissioned at Amatitlán, adding to the existing 5 MW_e back-pressure unit. However, the latter unit is currently out of service and INDE expects to transfer it to the next field – possibly Tecuamburro – to be developed some 2 or 3 years hence.

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.

Direct use of geothermal heat is limited but the 1.6 MW_t Bloteca plant is used in the process of curing concrete construction blocks and in another instance Agro-Industrias La Laguna uses a 0.5 MW_t unit to dehydrate fruit.

The direct-use of geothermal energy in the country in the past has been used for medical purposes, agriculture, and domestic use. The areas of Totonicapan, Quetzaltenango, and Amatitlan are popular tourist attractions known for their thermal bath houses and spas. These are estimated at a total of 0.21 MWt and 3.96 TJ/yr. The construction company, Bloteca, was the first to successfully apply a direct use application of geothermal steam in the curing process of concrete products (Merida, 1999).

In 1999, a fruit dehydration plant, Agroindustrias La Laguan, was built to use hot water from a well in the Amatitlan geothermal field in the drying process.

Hungary

	Electricity generation
Installed capacity MWe	
Annual output GWh	
Annual capacity factor	
	Direct use
Installed capacity, MWt	654.6
Annual output TJ	9 767
Annual capacity factor	

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.

The principal applications of geothermal power used directly are for balneological purposes, greenhouse heating, space heating, industrial process heat and other uses.

Surface signs have been known in the country since ancient times, and thermal springs in Budapest have been used during the Roman Empire and also later in the Medieval Hungarian Kingdom. Exploration for thermal waters began in 1877 and during the 1950s and 1960s hundreds of geothermal wells were drilled, mainly for agricultural utilization.

More recently, the use of geothermal energy has decreased substantially due to the global recession; however, promising projects are being investigated for both power production and direct-uses. Balneology was the earliest use of thermal waters, with 289 thermal wells and 120 natural springs presently used for sport and therapeutically purposes. Agricultural use is one of the important applications of geothermal waters in the country with 193 operating wells supplying heat for 67 ha of greenhouses. Animal farms use thermal water in more than 52 cases to raise chickens, turkeys, calves, pigs and snails. At present more than 40 townships with more than 9,000 flats are heated in district heating projects. Thermal waters are also used in secondary oil production with 5,400 m3/s of hot water being injected into oil reservoirs for enhanced oil recovery. In addition, gathering pipes in a heavy oil producing oilfield are heated with geothermal waters.

Iceland

	Electricity generation
Installed capacity MWe	665
Annual output GWh	4465
Annual capacity factor	
	Direct use
Installed capacity, MWt	2002.9
Annual output TJ	24621.4
Annual capacity factor	

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.

The principal use of geothermal energy is for space heating, with about 89% of all houses heated by geothermal resources. There is a total of about 30 municipally-owned geothermal district heating systems located in the country, the largest of which is Reykjavik. Iceland's geothermal capacity for electricity generation has increased dramatically in recent years and is today representing about 30% of total electricity generation. Geothermal accounted for 62% of Iceland's energy supply.

The policy of the Iceland Government is to expand the use of renewable energy to an even greater extent. Direct use of geothermal power has not grown to the same extent as electricity generation but it remains of major importance, especially in the residential sector.

Iceland's economy has been seriously impacted by the global economic situation, which has slowed the pace of geothermal development. Reykjavik Energy has revised its projected drilling plans and although the company will continue with projects, they will take longer to come to fruition.

Due to its location the country has very favourable conditions for geothermal development. The geothermal resources are utilized for both electricity generation and direct heat applications. It provides 62% of the nation's primary energy supply, with space heating the most important direct-use, providing 89% of all space heating in the country.
The largest geothermal district heating system is in Reykjavik where 197,404 people are served with an installed capacity of 1,264 MWt and peak load of 924 MWt.
Two other large district heating systems are located on the Reykjanes peninsula which serves about 20,000 people and the Akureyri system in northern Iceland serving about 23,000 people.

There are 135 swimming pools in the country that use geothermal heat, generally open throughout the year.

Snow melting has been recently increased to where 820,000 m2 are heated throughout the country, with most in Reykjavik. Most of the heat energy comes from the return water from space heating systems.

Industrial uses include the seaweed drying plant at Thorverk; carbon dioxide production at Haedarendi; and fish drying by 18 small companies, producing about 15,000 tonnes of dried cod heads for export. The diatomaceous earth drying plant at Kisilidjan has been closed. Other industrial applications using geothermal heat are salt production, drying of imported hardwood, retreading of car tires, wood washing, curing of cement blocks, and steam baking of bread at several locations.
After space heating, heating of greenhouses is the oldest and most important uses of geothermal energy. Crops produce include vegetables (55%) and flowers (45%), with an estimated 17.5 ha in operation at present. Fish farming has increased to around 10,000 tonnes in 40 plants by 2006, with salmon the main specie; however, arctic char and cod production are increasing rapidly.

India

	Electricity generation
Installed capacity MWe	
Annual output GWh	
Annual capacity factor	
	Direct use
Installed capacity, MWt	
Annual output TJ	
Annual capacity factor	

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.

Research has shown that there are 340 hot springs in India, most of which have a low-temperature resource and therefore only suitable for direct use. At the present time direct utilisation is almost entirely for bathing and balneological purposes. However, it is considered that greenhouse cultivation of fruit could be developed extensively in the future.

Investigative studies are being undertaken in order to establish the feasibility of developing the geothermal resource for power generation. The Ministry of New and Renewable Energy is supporting a RD&D programme for such studies. The State Governments of Jammu and Kashmir and Chhattisgarh have indicated their willingness to develop geothermal fields for commercial operation. The Government of Andhra Pradesh has initiated a resource assessment study and has proposed the demonstration and use of heat pumps in Gujarat.

An Action Plan for Indo-Iceland Geothermal Cooperation has been drawn up between the two Governments in order for Iceland's geothermal expertise to assist in developing the Indian resource.

It has been estimated from geological, geochemical, shallow geophysical and shallow drilling data it is estimated that India has about 10,000 MWe of geothermal power potential that can be harnessed for various purposes. Rocks covered on the surface of India ranging in age from more than 4500 million years to the present day and distributed in different geographical units. The rocks comprise of Archean, Proterozoic, the marine and continental Palaeozoic, Mesozoic, Teritary, Quaternary etc., More than 300 hot spring locations have been identified by Geological survey of India (Thussu, 2000). The surface temperature of the hot springs ranges from 35 C to as much as 98 C. These hot springs have been grouped together and termed as different geothermal provinces based on their occurrence in specific geotectonic regions, geological and strutural regions such as occurrence in orogenic belt regions, structural grabens, deep fault zones, active volcanic regions etc., Different orogenic regions are – Himalayan geothermal province, Naga-Lushai geothermal province, Andaman-Nicobar Islands geothermal province and non-orogenic regions are – Cambay graben, Son-Narmada-Tapi graben, west coast, Damodar valley, Mahanadi valley, Godavari valley etc.

Indonesia

	Electricity generation
Installed capacity MWe	1197
Annual output GWh	9600
Annual capacity factor	
	Direct use
Installed capacity, MWt	
Annual output TJ	
Annual capacity factor	

Having become a net oil importer early in the 21st century, Indonesia took the view that it was essential to harness the enormous geothermal resource at its disposal. The Government's National Energy Management Blueprint 2005–2025, contained a target of 9 500 MW_e geothermal capacity by 2025. The national geothermal potential has been estimated at 27.67 GW_e but at the present time only a tiny fraction of this has been realised. The island of Sumatra has in the region of 50% of geothermal potential.

In recent years the Indonesian Government has passed a raft of laws and regulations in order to better regulate both the upstream and downstream side of the sector and to better utilise its geothermal power. Additionally, the Japan International Cooperation Agency, at the request of the Government, was engaged to formulate a Master Plan Study for Geothermal Power Development. A period of 18 months in 2006/2007 was used to assess the fields and formulate a development plan.

By end-2008, a total of 1 054 MW_e geothermal capacity was installed, of which some 95% was based on the island of Jawa-Bali. The remaining 5% was located on Sumatera and Sulawesi. Of the total, Pertamina Geothermal Energy (PGE), a subsidiary of Pertamina, the state-owned oil and gas company, operates 252 MW_e, Chevron, 632 MW_e and other companies, 170 MW_e. Electricity production in 2008 amounted to 8.2 GWh.

A planned programme of construction will gradually increase capacity so that by 2025 about 50% of national electricity demand will be satisfied by geothermal power. It was announced during the World Geothermal Congress 2010 that Indonesia plans to launch a 3 997 MW_e project to expand geothermal power.

A very small amount of geothermal energy is used directly for bathing, balneology and swimming and in the production of mushrooms, tea, silk and coconut sugar drying.

The paper by Darma et al. focuses, as in the past on the development of electricity generation by geothermal energy, however five years ago a group of researchers in government sponsored research and technology agency (BPPT) began to investigate methods to apply geothermal energy to the agriculture sector, particularly to sterilize the growing medium used in mushroom cultivation.

The process is still at the research stage not having yet become commercial.

Other uses of geothermal fluids include palm sugar processing, copra drying, tea drying and pasteurization and some fish farming. These activities are spread over about six areas totaling about 200 – 300 tonnes/hr of fluid.

No heat pump installations are used to date as they appear to be uneconomical at this time due to the availability and abundance of high enthalpy fluids.

Iran

	Electricity generation
Installed capacity MWe	
Annual output GWh	
Annual capacity factor	
	Direct use
Installed capacity, MWt	
Annual output TJ	
Annual capacity factor	

Iran's geothermal potential is embodied in low- to medium-enthalpy resources found in provinces fairly widely distributed across the country. However, three regions, Damavand in the north-central area, and Maku-Khoy and Sahand in the northwest, are likely to be the most productive.

Traditionally, geothermal heat has been used directly for recreational and balneological purposes.

The country is extremely well-endowed with low-cost fossil fuels and historically 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. The Renewable Energy Organisation of Iran (SUNA), an affiliate of the Ministry of Energy was established in the 1990s. In recent years SUNA has studied the feasibility of, and given publicity to, using the heat for greenhouses, agriculture, aquaculture and heat pumps for cooling and heating purposes.

Ireland

	Electricity generation
Installed capacity MWe	
Annual output GWh	
Annual capacity factor	
	Direct use
Installed capacity, MWt	
Annual output TJ	
Annual capacity factor	

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 9 500 domestically installed systems (typically, 15 kW) exist. This trend is expected to continue. Additionally, more than 270 large-scale heat pumps have been installed in commercial buildings. In total, heat pumps represent some 164 MW_t of installed capacity.

Italy

	Electricity generation
Installed capacity MWe	772
Annual output GWh	5 754
Annual capacity factor	
	Direct use
Installed capacity, MWt	1000
Annual output TJ	12 600
Annual capacity factor	

Italy is one of the world's leading countries in terms of geothermal resources, lying fifth in terms of production of electricity from geothermal. 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_e unit. Subsequently the main emphasis has been on the production of power rather than on direct use of the heat.

The main geothermal fields in Italy are Larderello, the oldest and one of the most powerful in the world, with 200 production wells at depths of less than 1 000 to over 4 000 m, the Travale-Radicondoli, with 25 production wells at depths of between 1 500 and 3 500 m, and Bagnore and Piancastagnaio, with 16 production wells at depths of 2 500 – 4 000 m.

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. 31 plants are in operation with a total installed capacity of 810 MW_e (711 MW_e operating capacity). All plants in operation are located in the region of Tuscany and over 45% in the Province of Pisa. Electricity generation during the year amounts to 6.3 TWh, Although installed geothermal capacity represented only 3% of total renewable energy capacity, output accounted for 9.5% and Enel, the main Italian power company, already plans to increase capacity by installing a further 112 MW_e in the coming years. Expansion of capacity began in November 2009 when an additional highly-efficient facility was brought into operation.

Government and State support available for both geothermal plants and direct use of heat includes national mandatory quotas, tradable green certificates and financial incentives.

Although the country also utilises its low-enthalpy resources for direct purposes, it is considered that the market is still under-developed. Main applications for direct uses are thermal spas, space and district heating, fish farming, greenhouse heating, heat pumps and industrial process heat.

Heat pumps are being installed at a rate of some 500 per annum, most being groundwater types, with a smaller amount of closed-loop types. The growth potential of the direct use market is seen as greater than that of power generation. The Italian Position Paper foresees a potential capacity of 1 300 MW_e by 2020, while total use of geothermal heat might grow to 6 000 MW_t by 2020.

Geothermal direct-use has increased by a factor of 1.2 in the past five years to 867 MWt and 9,941 TJ/yr. This larger contribution, in terms of installed power, is mainly due to the wide development, mainly in the northern areas of Italy, of geothermal district heating and in the number of single household installations.

Both heating and cooling have been developed using geothermal energy, mainly by a large increase in geothermal heat pumps, both open and closed systems. Much of the growth has been due to interest from the designer's community, as well as the decrease in the cost of systems.

For centuries Italian people have largely used thermal waters for bathing, medical cures and relaxation, and the industry is still an important part of geothermal use, accounting for 32% of the annual energy use.

A number of district heating systems using geothermal energy are operating in the country, with Ferrara being the most important. A number of geothermal district heating systems are also operating in the Tuscany region.

Greenhouse heating and fish farming are also important parts of direct use applications, amounting to 13% and 16% respectively of the annual energy use. The largest greenhouse operation uses "waste" water from the Mt. Amiata power plant in Tuscany.
Large geothermal heat pump installations (2–5 MWt) have played an important role in Italy. Installations of geothermal heat pumps has increased 15% in the past year with an about 12,000 units installed.

Japan

	Electricity generation
Installed capacity MWe	538
Annual output GWh	2 632
Annual capacity factor	
	Direct use
Installed capacity, MWt	2 100
Annual output TJ	25 698
Annual capacity factor	

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 technological improvements were made. By end-1996, installed capacity stood at 529 MW_e but in the following years economic constraints were imposed, financial incentives withdrawn and geothermal capacity grew only marginally, reaching 535 MW_e in 2006. The existing plants are located on the southern island of Kyushu, in northern Honshu, at Mori on Hokkaido and on the island of Hachijo, some 300 km south of Tokyo.

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. Geothermal energy was excluded from the Special Measures Law for the Promotion of Utilisation of the New Energy in 1997 and moreover, suffered when the electricity market was deregulated. In 2003 the Renewable Portfolio Standard Law did include geothermal energy but only insofar as binary cycle plants were concerned. The 2008 New Energy Law does include geothermal in the definition of New Energy and in January 2010, the Ministry of Economy, Trade and Industry (METI) presented measures for the promotion of renewable energy. METI is providing support by means of subsidies, tax incentives, an RPS and feed-in tariffs, appropriate to the energy source. However, although 2020 targets for other renewable energies are high, geothermal power generation is only expected to grow minimally.

By far the most important utilisation of geothermal hot water I n Japan is for direct use. It can be classified into three categories: the thermal use of hot water; geo-heat pumps and hot springs for bathing. The last named has never until recently, been accurately quantified. Based on the consideration that there are more than 25 000 hot springs throughout the country, a figure of nearly 1 700 MW_t expressed in terms of fuel alternative energy was thought to represent this use in 2006. This estimate accounts for some 80% of total direct use. When recreational hot-spring bathing is excluded, the estimated 2006 total installed direct use capacity was 400 MW_t. Of this total, snow melting and air conditioning accounted for 38%; hot water supply and swimming pools, 31%; space heating, 19%; greenhouse heating, 9%; fish breeding 2%; and industrial and other uses, negligible. At the end of the year, some 13 MW_t of ground source heat pumps were estimated to be installed.

The direct use of medium- and low-enthalpy geothermal water is mainly located in the areas around the high-enthalpy geothermal area, where hot spring resources are abundant. Otherwise, the use of shallow geothermal heat pump systems is available nationwide. These latter installation account for only 0.3% of the direct-use, and thus have limited use in the country.

Kenya

	Electricity generation
Installed capacity MWe	169
Annual output GWh	1430
Annual capacity factor	
	Direct use
Installed capacity, MWt	16
Annual output TJ	127
Annual capacity factor	

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 further development of this potential, but in the past this has been impeded by financial constraints.

Twenty prospects lying in the Rift Valley have been identified as worthy of future study. However, to date wells have been drilled at only two sites: at Olkaria near Lake Naivasha (about 120 km northwest of Nairobi) and Eburru. Only the former has been exploited although there is a planned 2.5 MW_e power station at Eburru.

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 (Africa's largest geothermal power plant, co-financed by the World Bank, the European Investment Bank, KfW of Germany and KenGen) were commissioned in late-2003.

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. The 35 MW_e third stage became operational at the beginning of 2009, bringing the total installed capacity to 48 MW_e.

In December 2009 drilling of new wells began at Olkaria. It is expected that 10 new wells will be drilled at Olkaria IV, increasing total capacity by 140 MW_e.

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.

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 84 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.

Korea (Republic)

	Electricity generation
Installed capacity MWe	
Annual output GWh	
Annual capacity factor	
	Direct use
Installed capacity, MWt	
Annual output TJ	
Annual capacity factor	

With its heavy reliance on fossil fuels and nuclear power for electricity generation, Korea's energy supply structure has only in recent years come to fully embrace the renewable energies. The 2008 First National Energy Master Plan encompassed the Third Basic Plan on New & Renewable Energy Technology Development, Utilization and Diffusion, 2009–2030. Within the Third Basic Plan, the share of renewable energy aims to satisfy 11% of primary energy supply and 7.7% of electricity generation by 2030. Although the main emphasis of the Plan is directed towards solar PV and hydrogen/fuel cells, development of the geothermal heat pump sector is expected to play its part. Additionally, the Mandatory Public Renewable Energy Use Act which came into force during 2004 states that more than 5% of the budget for any new public building larger than 3 000 m^2 must be used to install renewable energy. This legislation is hastening the growth of geothermal heat pumps.

Lithuania

	Electricity generation
Installed capacity MWe	
Annual output GWh	
Annual capacity factor	
	Direct use
Installed capacity, MWt	48
Annual output TJ	412
Annual capacity factor	

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_t geothermal heat and 23 MW_t 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 south-western 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 an estimated 1 000 ground-source heat pumps, with an installed capacity of 17 MW_t.

Mexico

	Electricity generation
Installed capacity MWe	867
Annual output GWh	6 502
Annual capacity factor	
	Direct use
Installed capacity, MWt	156
Annual output TJ	4 023
Annual capacity factor	

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.

Comision Federal de Electricidad (CFE) has developed some direct uses of geothermal resources at the Los Azufres geothermal field, including a wood-dryer, a fruit and vegetables dehydrator, a greenhouse and a system for heating of its offices and facilities in this field.

The use of geothermal heat pumps is minimal, and underdeveloped with no information available. District and individual space heating is little used in Mexico due to the mild temperatures throughout the year in most of the country.

eothermal heat is obviating the need to use 3 million m^3 of natural gas. A second borehole was started in late-2008 in preparation for a doubling in the size of the greenhouses. It is expected that this application will encourage further use by horticulturists.

TNO, a Dutch research institute under contract to the Ministry of Economic Affairs, is currently mapping the deep heat resource in order to reassess the potential of the Netherlands. Analysis of deeper formations may demonstrate the feasibility of the resource for electricity generation.

Originally the object of drilling energy wells in the country was to store solar energy for space heating in winter. Later, this application broadened to the storage of thermal energy (both heat and cold) from other sources and to include geothermal heat pumps. The R&D of the early applications in the 1980s was focused on large scale applications such as commercial buildings rather than residential houses. Almost all of these early projects used ground water wells to store and extract thermal energy. In the late 1990s, borehole heat exchangers began to pay a more important role with geothermal heat pumps.

At present, most of the geothermal heat pumps projects are using vertical borehole heat exchangers, with over 10,000 of these in operation. Most are small scale applications such as for single family houses or small office and commercial buildings. Systems in family homes are designed for the heating load, whereas in commercial/office building the design is for both heating and cooling. Most projects use aquifer storage for both heating and cooling, with heat pump capacities in the 50 to 100 kWt range, and using ground water flow rates at less than 10 m3/hr (as no permits are need up to this rate). In Amsterdam about 1,200 large systems are installed with heat pump capacities around 1,000 kWt in some cases extracting over 250 m3/hr from a single well. Direct groundwater cooling is also practiced with the larger projects.

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. Thirteen years later following refurbishment by Ormat, the implementation of a new reservoir management plan and the installation of a 7.5 MW_e binary energy converter, the total nominal generation capacity stood at 77.5 MW_e. (at end-2008 effective capacity was 28.5 MW_e)

Nicaragua's net geothermal electricity output has been on a rising trend since 1999 and in 2008 totalled 289.8 GWh, just under 10% of total net generation.

Two of the ten identified areas of geothermal potential are currently being explored. GeoNico, a joint venture between the Italian company Enel and LaGeo of El Salvador, is exploring areas located in El Hoyo-Monte Galáan and Managua-Chiltepe.

Nicaragua will include 36 MW of geothermal energy to the national grid later this month. The 36 megawatts are part of the 72 megawatt geothermal energy field generated by the San Jacinto-Tizate, located in the municipality of Telica, province of León and the Pacific volcanic chain of Nicaragua.

Those 36 megawatts of renewable energy that will come in the next few days to the national grid will mean a decrease in fuel consumption.

In the second phase of the San Jacinto-Tizate geothermal energy project, to be concluded in late 2012 or early 2013, will generate another 36 megawatts, for a total of 72 new megawatts, bringing the energy savings will be up to 80 million dollars annually.

Papua New Guinea

	Electricity generation
Installed capacity MWe	
Annual output GWh	
Annual capacity factor	
	Direct use
Installed capacity, MWt	
Annual output TJ	
Annual capacity factor	

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. Since 2002 activity has focused 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 (LGL), 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 and in early 2007 a further 20 MW_e were added. The plant currently satisfies approximately 75% of current electricity demand.

During 2008 LGL approved a project to increase the annual processing capacity of its gold mining facility to approximately one million ounces per year, a rise of up to 240 000 ounces. The expansion is expected to be completed during 2012. Drilling is currently being undertaken to ascertain whether there are further reserves of geothermal steam that can be harnessed to supply the expanded facility with power.

Philipines

	Electricity generation
Installed capacity MWe	1904
Annual output GWh	10311
Annual capacity factor	
	Direct use
Installed capacity, MWt	3
Annual output TJ	40
Annual capacity factor	

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.

By end-2008 installed geothermal capacity stood at just under 2 GW_e. Of this figure 1.4 GW_e were considered dependable, representing about 11% of total electric generating capacity. Gross geothermal generation during the year amounted to 10.7 TWh which represented 17.6% of total electricity generation. Plants in the Visayas Islands generated 6.2 GWh; on the island of Luzon, 3.7 GWh and on the island of Mindanao, 0.8 GWh. Gross output in 2008 was 5% higher than in 2007, attributable to both the increased energy transfer from Leyte-Samar to Luzon via the Leyte-Luzon High Voltage Direct Current link – up from 720 GWh to 1 117 GWh and the unavailability of Luzon's coal-fired plants and thus the greater use of geothermal power.

The 2007 Update to the Philippine Energy Plan states the Government's determination to achieve a greater than 60% energy self-sufficiency beyond 2010. In December 2008 the Government legislated for a Renewable Energy Act to come into force at the end of January 2009. The objective of the Act is to accelerate the use of renewable energy so that the country will be able to raise its two-thirds self-sufficiency in electricity generation to possibly as high as 90%. To this end many market development incentives are being put in place. The target for additional geothermal capacity is 790 MW_e.

Direct use of geothermal heat is currently at a low level and is used for agricultural drying and bathing and swimming. The Government plans to further develop direct utilisation.

Direct-use of geothermal energy in the country is very limited. Two agricultural drying plants using geothermal heat are located at Palinpinon and Manito. The Palinpinon project uses steam from the Southern Negros Geothermal Projects (Palinpinon I geothermal power plant) where coconut meat and copra are dried (Chua and Abito, 1994).

The main resorts using geothermal heat are at Laguna and Agco.

The various applications are:

- 1.63 MWt and 26.93 TJ/yr for agricultural draying (the majority at the Palinpinon plant);
- 1.67 MWt and 12.65 TJ/yr for bathing and swimming;

Poland

	Electricity generation
Installed capacity MWe	
Annual output GWh	
Annual capacity factor	
	Direct use
Installed capacity, MWt	281
Annual output TJ	1501
Annual capacity factor	

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.

Since 1992 seven geothermal heating plants have been brought on line: three in the Podhale region (Zakopane, Bukowina Tatrzańska and Bańska Niżna), in Stargard Szczeciński and Pyrzyce (both in the northwest) and in Mszczonów and Uniejow (both in central Poland). The plants are utilised for different purposes according to specific characteristics of the water at each location: some are used with gas peaking – the integrated units have a large contribution from gas, others have integrated absorption heat pumps with gas boilers.

Geothermal water is also used at eight balneological installations. It is estimated that there are about 10 000 compression heat pumps – mostly ground source – within the country with an installed capacity of at least 100 MW.

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+°C water.

Poland is characterized by low-enthalpy geothermal resources found mostly in the Mesozoic sedimentary formations. For many centuries warm springs have been used for balneotherapy in several spas. At present five geothermal heating plants are in operation, the largest in the Podhale region in southern Poland with an installed capcity of 41 MW and producing 267 TJ/yr (peak). Seven new bathing centers opened in the past five years.

Other types of geothermal use include greenhouse heating, wood drying, fish farming (these three are at the Podhale Geothermal Laboratory as R&D projects), and salt extraction from geothermal water.

Geothermal heat pumps installations have increased by at least 50% over the past five years with three large units in two major heating plants (water-source units), and over 11,000 units in individual buildings (ground-coupled units, both vertical and horizontal).

The various uses include:

- district heating of 68.0 MWt and 393 TJ/yr;
- greenhouse heating 0.5 MWt and 2.0 TJ/yr;
- fish farming 0.5 MWt and 2.0 TJ/yr;
- bathing and swimming 8.67 MWt and 55.2 TJ/yr;
- geothermal heat pumps at 203.10 MWt and 1,044.5 TJ/yr;
- others (salt extraction and playground heating) 0.28 MWt and 4.4 TJ/yr;

Portugal

	Electricity generation
Installed capacity MWe	30
Annual output GWh	210
Annual capacity factor	
	Direct use
Installed capacity, MWt	28
Annual output TJ	420
Annual capacity factor	

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. Operation of the 3 MW_e Pico Vermelho on São Miguel began in 1981. A second plant came into operation in two phases in 1994 and 1997 and by end-2008 gross geothermal capacity had reached 28.2 MW_e, generating 192 GWh.

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.

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-2009, total installed capacity stood at 27.8 MW_t of which 25.3 MW_t was for bathing and swimming, 1 MW_t for greenhouse heating and 1.5 MW_t for district heating.

High temperature geothermal resources in Portugal are limited to the volcanic islands of the Azores, where electric power has been produced since 1980.

Low-temperature geothermal resources are exploited for direct uses in balneotherapy, small space heating systems and geothermal heat pumps. In 2008, private investors obtained concession rights for exploration of geothermal resources for a total area of 2,655 km2, aiming for future development of small scale EGS generation projects. District heating projects are operating at Chaves in northern Portugal and S. Pedro do Sul, in central Portugal. There is a single greenhouse project in S. Pedro do Sul covering 2 ha, for raising tropic fruit (mainly pineapple). About 30 spas are operating in the country, but most are only open in the summer. Several dozen small geothermal heat pump installations are operating throughout the country, but unfortunately, this application is not recognized as a geothermal resource by the Portuguese administration.

The data on the various geothermal utilizations are:

- 1.5 MWt and 12.9 TJ/yr for district heating;
- 1.0 MWt and 13.8 TJ/yr for greenhouse heating;
- 25.3 MWt and 358.6 TJ/yr for bathing and swimming.

No estimates were made for geothermal heat pumps, thus we estimate 24 installations at 12 kW, a COP of 3.5 and 1,500 full load operating hours per year, gives 0.3 MWt and 1.1 TJ/yr.

Romania

	Electricity generation
Installed capacity MWe	
Annual output GWh	
Annual capacity factor	
	Direct use
Installed capacity, MWt	174
Annual output TJ	1 520
Annual capacity factor	

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 and then as an unexpected result of a hydrocarbon research programme. To date more than 250 exploration wells have been drilled. Completion and experimental exploitation of more than 100 wells during the past 25 years has enabled the evaluation of the heat available from this resource. The geological research programme is continuing, with a few new wells drilled each year, all being usually completed as potential production or 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. The installed capacity of 174 MW_t is utilised for space and district heating, bathing and swimming (including balneology), greenhouse heating, industrial process heat, fish farming and animal husbandry.

Near and mid-term plans include drilling of new production and reinjection wells, expansion of existing district heating schemes and development of some new ones, expansion of greenhouse heating and development of health and recreational bathing facilities. There is an evaluated potential in Romania of 20 MW_e for power generation and thus research will be undertaken into the possible use of binary plants.

The main geothermal resources in the country are found in porous and permeable sandstones and siltstones (such as in the western plains), or in the fractured carbonate formations (such as at Oradea and Bors in the western part of the country).

The total capacity of the existing wells is about 480 MWt; however, only about 148 MWt from 80 wells are currently used. 35 of these wells are used for balneology and producing water at temperatures from 40 to 115oC. During the last five years seven geothermal wells have been drilled in the country with National financing, with some to depths of 1,500 to 3,000 m producing up to 90oC water.
There are two main companies in Romania currently exploiting geothermal resources: Transgex S.A. and Foradex S.A., have been given long term concession for practically all known geothermal reservoirs. Transgex, the most active company, is looking at developing district heating projects in a number of communities. The University of Oradea has established a Geothermal Research Center which provides geothermal training and research.

The current direct utilization in the country includes:

- 13.28 MWt and 164.83 TJ/yr for individual space heating;
- 58.95 MWt and 531.72 TJ/yr for district heating;
- 4.18 MWt and 20.78 TJ/yr for greenhouses (8 locations);
- 4.50 MWt and 9.70 TJ/yr for fish farming (one location);
- 1.40 MWt and 12.70 TJ/yr for agricultural drying;
- 0.75 MWt and 6.84 TJ/yr for industrial process heat (4 locations);
- 64.68 MWt and 489.16 TJ/yr for bathing and swimming;
- and an estimated 5.5 MWt and 29.70 TJ/yr for geothermal heat pumps.

Russian Federation

	Electricity generation
Installed capacity MWe	82
Annual output GWh	441
Annual capacity factor	
	Direct use
Installed capacity, MWt	308
Annual output TJ	6 144
Annual capacity factor	

The Russian Federation has a significant geothermal resource, with thermal waters of 50–200°C having been identified in numerous areas from Kaliningrad in the west to the Russian Far East. In the Kamchatka Peninsula and the Kuril Islands the thermal water reaches 300°C. It has been estimated that the high-temperature resources defined to date in the Peninsula could ultimately support generation of 2 000 MW_e. and 3 000 MW_t of heat for district heating. Exploration has shown that the discovered geothermal resource of Kamchatka could provide the peninsula's total demand for both heat and electricity for in excess of 100 years.

The country's energy sector has long been based on fossil fuels and the exploitation of hydroelectric and nuclear power. The contribution from geothermal energy represents a very small percentage. 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, south of Kamchatka in 1966. Four further plants were installed in 1999, 2002 and 2007 and by end-2008, total installed capacity stood at 81.9 MW_e. A 2.5 MW_e plant in Kamchatka and a 3.2 MW_e plant are currently under construction.

The use of geothermal heat for direct purposes is widespread and has mostly been developed in the Kuril-Kamchatka region, Dagestan and Krasnodar Krai. Many district heating and greenhouse heating schemes already exist, together with use of geothermal heat for industrial processes, cattle and fish farming, drying of agricultural products, and swimming pools and baths. There are plans for greater exploitation in Krasnodar Krai and the regions of Kaliningrad and Kamchatka.

There is much scope for the installation of heat pumps in Russia, but their use is presently at an early stage of development.

In January 2009 the Russian Prime Minister signed an Executive Directive for a greater use of renewable energy in order for the efficiency of the electric power sector to be improved. The targets for the share of renewable energy in electricity generation are 1.5% in 2010, 2.5% in 2015 and 4.5% by 2020. At the beginning of 2010 it was reported that a Ministerial MOU had been signed between Finland and Russia. The stated objective is that cooperation and shared knowledge will lead to greater energy efficiencies and improved utilisation of renewable energies.

Direct use of geothermal resources is mostly developed in the Kuril-Kamchatka region, Dagestan and Drasnodar Krai, mainly for district and greenhouse heating.

To date, 66 thermal water and steam-and hydrothermal fields have been exploited in Russia. Half of them are in operation providing approximately 1.5 million Gkal of heat annually (Povarov and Svalova, 2010). Approximately half of the extracted resource is used for space heating, a third for heating greenhouses, and about 13% for industrial processes. There are also approximately 150 health resorts and 40 factories bottling mineral water.

Heat pumps are at an early stage of development in Russia. An experimental facility was set up in early 1999 in the Philippovo settlement of the Yaroslavl district. Eight heat pumps are used for a 160-pupil school building. There are also some buildings using heat pumps in Moscow (Svalova, 2010).

A district heating project is being proposed for Vilyuchinsk City on Kamchatka (Nikolskiy et al., 2010).

Serbia

	Electricity generation
Installed capacity MWe	
Annual output GWh	
Annual capacity factor	
	Direct use
Installed capacity, MWt	119
Annual output TJ	3 244
Annual capacity factor	

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 thermal spas for balneology and recreation. However, the 97 MW_t installed capacity is used for bathing and swimming, space heating, greenhouses, fish and other animal farming, industrial process heat and agricultural drying. In addition, about 22 MW_t of thermal water heat pumps are in use.

The most common use of geothermal energy in the country is for balneology and recreation. Archeological evidence indicates similar uses by the Romans in the locations of the present spas such as Vranjuska, Niska, Vrnjacka and Gamzigradska.

Today there are 59 thermal water spas in the country used for balneology, sports and recreation and as tourist centers. Thermal waters are also bottled by nine mineral water bottling companies. Space heating and electric power generation from geothermal energy is in the exploration stages. There are presently 25 wells in use within the Pannonian Basin, and with uses for heating greenhouses (4 wells), heating pig farms (3 wells), industrial process such as in leather and textile factories (2 wells), space heating (3 wells) and 13 wells for various uses in spas and for sport and recreation facilities. Outside the basin, geothermal water is used for space heating, greenhouse heating (raising flowers), a poultry farm, a textile workshop, a spa rehabilitation center and a hotel. Three other spas and rehabilitation centers also use geothermal heat, including heat pumps of 6 MWt, which uses water at 25oC, and in the carpet industry.
The various applications include:

- 20.9 MWt and 356 TJ/yr for space eating;
- 18.5 MWt and 128 TJ/yr for greenhouse heating;
- 6.4 MWt and 128 TJ/yr for fish and animal farming;
- 0.7 MWt and 10 TJ/yr for agricultural drying;
- 4.6 MWt and 58 TJ/yr for industrial process heating;
- 39.8 MWt and 647 TJ/yr for bathing and swimming;
- 9.9 MWt and 83 TJ/yr for geothermal heat pumps.

Slovakia

	Electricity generation
Installed capacity MWe	
Annual output GWh	
Annual capacity factor	
	Direct use
Installed capacity, MWt	132
Annual output TJ	3 067
Annual capacity factor	

Slovakia's geothermal resources, first explored during the 1970s, have been located in 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: bathing and swimming, district heating, greenhouse heating and fish farming.

Several projects are under development: a greenhouse heating scheme in Podhajska; a district heating scheme in Galanta and a space heating project in Slovakia's second city, Košice. The Košice scheme is in the final stage of preparation, having obtained the necessary permits and awaits the go-ahead prior to implementation.

Geothermal direct-use is distributed in eight counties in the country with Nitra County (south-west of the center of the country) having the highest number of locations (19), and Trnava Country (western Slovakia) having the highest amount of thermal energy used. The smallest number of uses is in Kosice Country (eastern Slovakia) with five locations reported; however, this area has the highest potential for geothermal use in the country, including the generation of electricity.

Greenhouse heating is reported in 11 locations, two of which receive heat at the end of a cascaded system. Vegetables and cut flowers are the main products grown in these green-houses. There are 19 installation using geothermal energy for individual space heating and two locations for district heating. The main district heating system is for heating of blocks of flats and a hospital in Galanta.

There are 59 locations using geothermal water for swimming pools, both outside and inside. For some, the combined utilization (cascaded use) of the energy is for greenhouse heating, district heating and finally for bathing – in Topolniky and Podhajska. Two locations use geo-thermal energy for fish farming. There are also nine locations using geothermal heat pumps with a total of 16 units installed.

The various direct-uses include:

- 16.7 MWt and 381.1 TJ/yr for individual space heating;
- 10.8 MWt and 232.0 TJ/yr for district heating;
- 17.6 MWt and 461.1 TJ/yr for greenhouse heating;
- 11.9 MWt and 271.0 TJ/yr for fish farming;
- 73.6 MWt and 1,708.5 TJ/yr for bathing and swimming;
- 1.6 MWt and 13.5 TJ/yr for geothermal heat pumps.

Spain

	Electricity generation
Installed capacity MWe	
Annual output GWh	
Annual capacity factor	
	Direct use
Installed capacity, MWt	120
Annual output TJ	
Annual capacity factor	

Research has shown that a low-enthalpy geothermal resource is widely distributed across the Spanish mainland. The main areas are in the northeast, southeast, northwest and the centre. 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.

To date the geothermal resource has not had a major role in the Spanish energy economy. However, at the end of 2007, geothermal gained a higher profile within the Institute for the Diversification and Saving of Energy (IDEA) with the creation of the Hydroelectric and Geo-thermal Department, which together with the Instituto Geológico y Minero de España (IGME), will promote the technology and utilisation of geothermal energy. At the end of 2008, the country became a member of the IEA Implementing Agreement for Cooperation in Geother-mal Research and Technology.

There is a limited amount of capacity installed for direct purposes: – some 6 MW_t utilised for individual space heating, greenhouse heating and swimming and bathing.

Geothermal resource exploration, assessment and evaluation started through Spain in the seventies with a general geological and geochemical survey of known thermal springs and areas showing signs of thermal activity.. Over the following decades, each of the selected areas has been investigated utilizing techniques from geology, geophysics, geochemistry and related disciplines, the intensity of the investigation depending on each area's geothermal potential. Lastly, deep drilling has been done, enabling the geothermal potential of the more important areas to be evaluated. These major areas are located in the southeast (Granada, Almería and Murcia), northeast (Barcelona, Gerona and Tarragona), northwest (Orense, Pontevedra and Lugo) and center (Madrid) of the Iberian Peninsula. Other, more minor areas located in Albacete, Lérida, León, Burgos and Mallorca have also been investigated.

The geothermal resources evaluated in all these cases exhibit low temperatures, 50–90 °C. The only area where high-temperature fluids might possibly exist at depth lies in the volcanic archipelago of the Canary Islands. Hot dry rock resources have been evaluated on the islands of Lanzarote and La Palma. On the island of Tenerife, the presence of high-temperature areas has been investigated, but no commercially viable geothermal reservoirs have been found.

Low-temperature geothermal sites are currently being exploited on a small scale. For example, geothermal fluids are being used for heating and to provide hot water to spa buildings in Lugo, Arnedillo (in La Rioja), Fitero (in Navarra), Montbrió del Camp (in Tarragona), Archena (in Murcia) and Sierra Alhamilla (in Almería). In Orense and Lérida, geothermal waters are being used to heat homes and schools. Greenhouses are being geothermally heated at Montbrió del Camp (Tarragona), Cartagena and Mazarrón (in Murcia), and Zújar (in Granada); these facilities cover a total area of over 100,000 m2.

Sweden

	Electricity generation
Installed capacity MWe	
Annual output GWh	
Annual capacity factor	
	Direct use
Installed capacity, MWt	4 460
Annual output TJ	45 301
Annual capacity factor	

Sweden's utilisation of deep geothermal heat is on a very limited scale. however, Lund, in the far south of Sweden, has two heat pumps totaling about 47 MW_t providing base-load heat to a district heating network. The plant was connected to the network in 1984 and started heat production in 1985.

There are many small ground-source heat pumps installed in the country. It is reported that more than 350 000 small heat pumps have been installed in residential and official buildings, providing an estimated 10% of heat demand.

The Swedish Deep Drilling Program began in 2007. The purpose of the Program is to 'study fundamental problems of the dynamic Earth system, its natural history and evolution'. In 2009 a grant was awarded for a mobile truck-mounted drillrig that is capable of reaching a depth of 2 500 m. Supported by the International Scientific Drilling Program, drilling is planned to begin in 2011.

The majority of the heat pumps are small and typically used in single houses. There are currently around 230,000 installations with about 25,000 units installed annually. Bedrock-soil-water is the most common source for heat pumps using geothermal energy with about 12 TWh of energy extracts or about 15% of the national heat demand covered. A number of systems used underground thermal energy storage UTES), either as aquifer thermal energy storage (ATES) orborehole thermal energy storage (BTES). The former was implemented in the mid 1980s and current there are approximately 100 plants using this system, mainly large scale with average capacity of 2.5 MWt.
Water wells are used and serve a dual function, both as production and injections wells, with the flow direction being reversed from summer to winter. The BTES systems consist of a number of closed spaced boreholes, normally 50 to 200 m deep. These are equipped with borehole heat exchanger, with the holes filled with ground water and not grouted. It has been shown that water filled boreholes are more efficient than grouted ones. These are typically used for combined heat and cooling of commercial and institutional buildings. The reported total for UTES is 90 MWt and 504 TJ/yr for heatings and 90 MWt and 612 TJ/yr for cooling.

Switzerland

	Electricity generation
Installed capacity MWe	
Annual output GWh	
Annual capacity factor	
	Direct use
Installed capacity, MWt	U
Annual output TJ	8799
Annual capacity factor	

Switzerland's installed geothermal capacity 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 at the present time). 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.

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.

The use of geothermal energy for direct-use has increased substantially, mainly with the installations of geothermal heat pumps (GHP). GHP have increased at rates up to 17% per year, with borehole heat exchangers-coupled systems dominating.

The second largest use of geothermal energy is with thermal spas and wellness facilities. The proportion of the various uses in terms of energy use (GWh) is 73.9% for HE and horizontal loops, 13.6% for balneology, 10.4% using shallow groundwater, 1.0% using geostructures (energy piles), 0.6% using deep aquifers which includes using tunnel water. With about one GHP installed on the average every square km, this is the highest concentration in the world.

Tanzania

	Electricity generation
Installed capacity MWe	
Annual output GWh	
Annual capacity factor	
	Direct use
Installed capacity, MWt	
Annual output TJ	
Annual capacity factor	

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°C) fluids beneath the volcanoes.

Hot springs have 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°C and a reservoir temperature of 220–276°C.

Presently the country's geothermal resource is not utilised. However, and especially in the light of the growing energy demand, the National Energy Policy drafted in 2003 showed the need to assess the potential and establish its viability.

Estimates indicate that the geothermal potential of Tanzania is as high as 650 MW. Based on first assessment, the potential was adjusted to be in the order of 140 to 380 MW. This value is based on the natural heat discharge from hot springs. Provided that geothermal reservoirs exist, the potential could be even higher.

There are at least 15 hot springs in Tanzania with water temperatures above 40°C. They have been found in three regions:

Thailand

	Electricity generation
Installed capacity MWe	0.3
Annual output GWh	2
Annual capacity factor	
	Direct use
Installed capacity, MWt	3
Annual output TJ	79
Annual capacity factor	

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°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.

Based on communications from Praserdvigai (2005), an estimate of 2.54 MWt and 79.1 TJ/yr are currently installed and being utilized at a 0.3 MWe binary plant at Fang in Chiang-Mai province. A small crop-drying facility and air-conditioning unit are utilizing the exhaust from the power plant.

Turkey

	Electricity generation
Installed capacity Mwe	114
Annual output GWh	617
Annual capacity factor	
	Direct use
Installed capacity, MWt	2 084
Annual output TJ	36 886
Annual capacity factor	

A significant factor in Turkey's high geothermal potential is the fact that the country lies in the Alpine-Himalayan orogenic belt. It has been determined that Western Anatolia, containing the areas of most significance, accounts for about 78% of the 31.5 GW potential.

Geothermal exploration began during the 1960s, since when about 186 fields have been identified. Although some of these are high-enthalpy fields, 95% are low-medium enthalpy resources and thus more suited for direct-use applications.

Turkey has extensive geothermal resources, that have been utilized for heating of residences, district heating, greenhouse heating and for spas.

There are a total of 260 spas in the country using geothermal water for balneological purposes. There is also a liguid carbon dioxide and dry ice production factory integrated with a power plant at Kizildere.

Greenhouse heating has increased substantially in the last three years, with installations in six major areas covering 230 ha.

Tourism is also an important industry with over 12 million local and 10,000 foreign visitors benefiting from the balneological aspects of hot springs and spas.

Uganda

	Electricity generation
Installed capacity MWe	
Annual output GWh	
Annual capacity factor	
	Direct use
Installed capacity, MWt	
Annual output TJ	
Annual capacity factor	

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 have shown that the three prospects, Katwe-Kikorongo, Buranga and Kibiro have an estimated potential of 450 MW and if the temperatures of 140–200°C, 120–150°C and 200–220°C respectively are confirmed, then production or electricity and direct use in industry and agriculture could follow. Further investigative work is to be undertaken on these known prospects and in other areas of the country.

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.

The famous hot springs at Bath have long been a tourist attraction among the Roman architecture of the ancient city. Now the baths, together with four adjacent buildings, have undergone a major refurbishment, and have been reopened in 2008 and are now fully operational.

The ongoing increase in geothermal heat pumps is estimated to be in the range of 3,000 to 5,000 installations per year. A few of these installations are large scale open loop systems (~500 kW to 2 MWt), the majority are closed loop systems in the range of 3.5 kW heating only, with approximately 750 units at commercial/institutional sites and 4,500 units at residential sites with full load operating hours per years of 1,500 and 1,800 respectively. The main driver for the geothermal heat pumps activity in UK has been the understanding that if connected to the UK grid they can offer significant reductions in overall carbon emissions compared to traditional methods of heat delivery.

United States of America

	Electricity generation
Installed capacity MWe	3102
Annual output GWh	15 009
Annual capacity factor	
	Direct use
Installed capacity, MWt	12 612
Annual output TJ	56 551
Annual capacity factor	

The USA possesses a huge geothermal resource, 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.

Nine States use their geothermal resource for electricity. California accounts for the majority share at 83%. Nevada follows with 14% and at the other end of the spectrum, New Mexico, Oregon and Wyoming each have less than 0.01%.

The DOE states that an additional capacity totaling 80 MW_e is under construction and a further 234 MW_e is planned. Geothermal systems, with a potential capacity of 9 057 MW_e have been identified in 13 western States, approximately 5 800 MW_e more than that currently operating. Based on Geographic Information Systems statistical models, the mean estimated undiscovered resources in the 13 States is more than 30 GW_e.

The DOE's Geothermal Technologies Program is focused on Enhanced Geothermal Systems (EGS) technology, with activities ranging from site selection for future development to site characterisation, reservoir creation and validation, interwell connectivity, reservoir scale-up and reservoir sustainability. On the assumption that this technology is successfully implemented, models yield an estimated mean electric power resource on private and accessible public land of 517 800 MW_e in the 13 States. Development of an EGS R&D demonstration project at Desert Peak, Nevada is under way.

Most of the direct use applications have remained fairly constant over the past five years; however, geothermal heat pumps have increased significantly. A total of 20 new projects have come on-line in the past five years and a number of projects have closed.

Agricultural drying has decreased the most due to the closing of the onion/garlic dehydration plant at Empire, Nevada. Two district heating projects have also shut down; the Litchfield Correctional Facility in California and the New Mexico State University system.

There has been a slight increase in snow melting, cooling and fish farming, with a major increase in industrial process heating due to two biodiesel plants (Oregon and Nevada), a brewery (Oregon), and a laundry (California) coming on line.

Annual figures 1.16 % of the country's total electricity production output.

United Kingdom

	Electricity generation
Installed capacity MWe	
Annual output GWh	
Annual capacity factor	
	Direct use
Installed capacity, MWt	187
Annual output TJ	850
Annual capacity factor	

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.

Historically there has been no direct Government support for geothermal energy and the only application of low-enthalpy geothermal energy is the scheme, launched in 1986 in the city of Southampton. The scheme now supplies more than 40 GWh/yr of heat, 26 GWh of electricity from the combined heat and power plant and over 7 GWh of chilled water for air conditioning.

The Government has announced that it will provide GBP 6 million for exploration of the potential for deep geothermal power in the UK. Past research has shown the southwest region of England to be an area particularly rich in this resource.

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

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Geothermal heat suitable for direct utilisation is far more widespread, ranging from New York State in the east to Alaska in the west. Bathing and swimming (113 MW_t), district heating (75 MW_t), space heating (140 MW_t), agricultural drying (22 MW_t), industrial process heat (17 MW_t), snow melting (3 MW_t) and air conditioning (2 MW_t) are the main users of geothermal heat.

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On present estimates, there are at least one million units installed, mainly in the Midwestern and eastern states. Approximately 90% of the units are closed loop (ground-coupled) and the remaining open loop (water-source). It is presently a US$2 to US$3 billion annual industry in the country.

Vietnam

	Electricity generation
Installed capacity MWe	
Annual output GWh	
Annual capacity factor	
	Direct use
Installed capacity, MWt	
Annual output TJ	
Annual capacity factor	

The government-supported exploration and evaluation of the country's geothermal resource has shown that there is a total of 269 prospects of which 30 sites, with a capacity of 340 MW_e have been identified as being capable of power generation. The south-central, north-western and northern regions are the areas of Vietnam with the greatest potential. At the present time there is no geothermal power generation. Direct utilisation is limited to the provision of industrial process heat (iodide salt production) and bathing and swimming. The theoretical capacity of direct use has been estimated at 472 MW_t, of which 200 MW_t could be in operation by 2020.

Presently, there are more than 200 sources of hot water at temperatures of 40–100 degrees centigrade in Vietnam. Thermal reserves in the Red River Delta alone can be utilized to generate 1.16 % of the country's total electricity production output.

10

Wind

Contents

Strategic insight

1. Introduction

Wind has many applications, including electricity generation. It is available virtually everywhere on earth, although there are wide variations in wind strengths. The total resource is vast; one estimate (Cole, 1992) suggests around a million GW '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) that would still correspond, roughly, to the total worldwide capacity of all electricity-generating plant. The offshore wind resource is also vast, with European resources, for example, capable of supplying all the European Union's electricity needs, without going further than 30 km offshore.

The location of the 'best' onshore wind resources, based on maps by Czisch (2001), and the analysis of Archer and Jacobson (2005) is summarised in Fig. 10.1, which shows that wind energy resources are well distributed.

Figure 10.1

Summary of locations of the most attractive regions for wind energy

Source: Czisch, 2001

Region	Location
Europe	North and west coasts of Scandinavia and the UK, some Mediterranean regions
Asia	East coast, some island areas, Pacific Islands
Africa	North, southwest coast
Australasia	Most coastal regions
North America	Most coastal regions, some central zones, especially where mountainous
South America	Best towards the south, coastal zones in east and north

The rapid growth of wind energy may be demonstrated by noting that the projection for 2010 set out in the European Commission's White Paper on renewable energy (EC, 1997), was 40 GW. That was 16 times the capacity in 1995, but the target was realised by 2005 and by late 2009, European capacity was over 72 GW.

World wind energy capacity has been doubling about every three and a half years since 1990. It is doubtful whether any other energy technology is growing, or has grown, at such a rate. Total capacity at the end of 2008 was over 120 GW and annual electricity generation around 227 TWh, roughly equal to Australia's annual consumption. The United States, with about 25 GW, has the highest capacity but Denmark with over 3 GW, has the highest level per capita, and production there corresponds to 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 wind capacity is located onshore but offshore wind sites have been completed, or are planned, in China, Denmark, Ireland, Sweden, Germany, the Netherlands, the UK and elsewhere. By end-2009, over 1 500 MW was operational. Offshore wind is attractive in locations where pressure on land is acute and winds may be 0.5 to 1 m/s higher than onshore, depending on the distance from the coast. The higher wind speeds do not presently compensate for the higher construction costs, but the chief attractions of offshore are its larger resource potential and lower environmental impact.

Early machines - 25 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 over 3 MW and diameters around 60-80 m; machines for the offshore market have outputs up to 6 MW and diameters up to 126 m. The average rating of turbines installed in Germany in 1992 was 180 kW and in 2008 it was just under 2 000 kW – over ten times as much.

Machine sizes have increased for two reasons. They 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. Energy yields, in kWh per square metre of rotor area, are now double those of 1990 (Welke and Nick-Leptin, 2006). In 2008, data from the Danish Energy Agency showed that the most productive machines delivered around 1 500 kWh per square metre of rotor area. Reliability has also improved steadily and availabilities of 95% or more are common.

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. However, the market is evolving and there are numerous other options. 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 established. These also allow variable-speed operation, which brings several advantages - it means that the rotor turns more slowly in low winds (which keeps noise levels down), it reduces the loadings on the rotor, which can operate with higher efficiency, and the generators are usually able to deliver current at any specified power factor. Direct drive systems are becoming increasingly common. These eliminate the gearbox and 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 small machines in the range 100 kW and below. Recent increases in the price of steel have reawakened interest in concrete towers but there are relatively few examples yet.

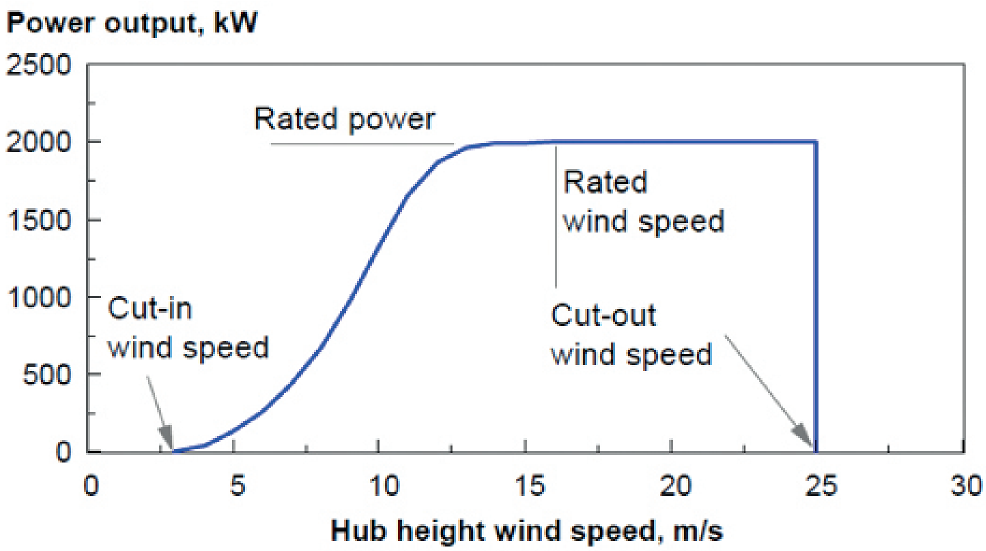
As the power in the wind increases with the cube of the wind speed, all wind turbines need to limit the power output in very high winds. There are two principal means of accomplishing this, with pitch control on the blades or with fixed, stall-controlled blades. Pitch-controlled blades are rotated as 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 much more popular.

Annual energy production from the turbine whose performance is charted is around 2 457 MWh at a site where the wind speed at 78 m height is 5 m/s, 5 629 MWh at 7 m/s and 6 725 MWh at 8 m/s. Wind speeds around 5 m/s can be found, typically, away from the coastal zones in all five continents, but developers generally aim to find higher wind speeds. Levels 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 UK, Spain, New Zealand and Antarctica. Offshore wind speeds are generally higher than those onshore – around 8 m/s in European coastal waters, for example.

Figure 10.2

Power curve and key concepts for a 2MW wind turbine

Source: Vestas Wind Systems A/S



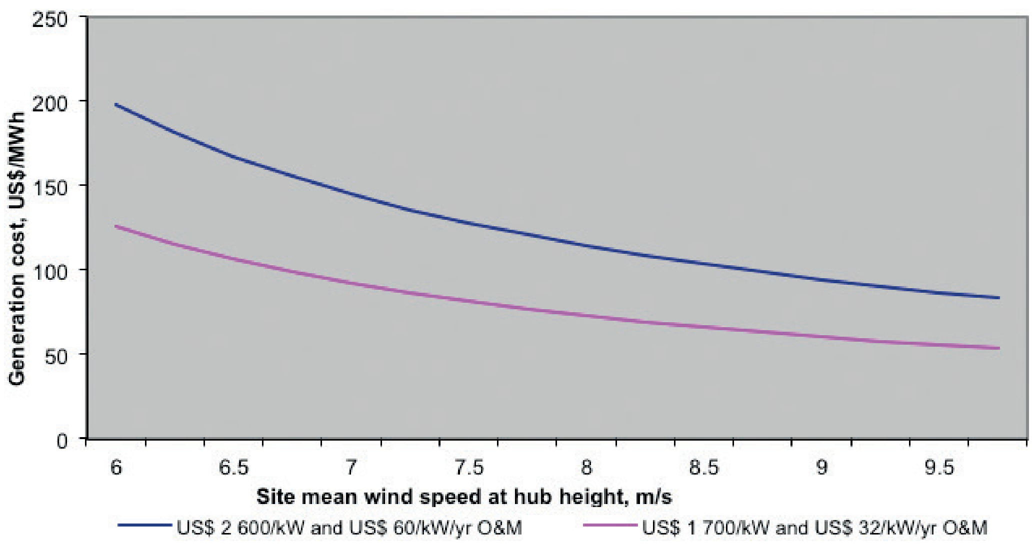
The cost of wind energy plants fell substantially during the period from 1980 to 2004. Prices in the 1980s were around US$ 3 000/kW, or more, and by 1998 they had come down by a factor of three. During that period the size of machines increased significantly - from around 55 kW to 1 MW or more - and manufacturers increased productivity substantially. In 1992, for example, one of the major manufacturers employed over seven people per megawatt of capacity sold, but by 2001 only two people per megawatt were needed. The energy productivity of wind turbines also increased during this period. This was partly due to improved efficiency and availability, but also due to the fact that the larger machines were taller and so intercepted higher wind speeds. A further factor that led to a rapid decline in electricity production costs was the lower operation and maintenance costs.

With capital costs halving between 1985 and the end of the century, and productivity doubling, it could have been expected that electricity production costs would fall by a factor of four. This general trend has been confirmed by data from the Danish Energy Agency; these suggest that generation costs fell from DKK 1.2/kWh in 1982 to around DKK 0.3/kWh in 1998 (Danish Energy Agency, 1999).

Shortly after the turn of the century, the downward trend in wind turbine and wind farm prices halted and prices moved upwards. This was partly due to significant increases in commodity prices and partly due to shortages of wind turbines. Prices appear to have peaked in 2008, with complete wind farms averaging just under US$ 2 200/kW and wind turbines at just under US$ 1 600/kW. Prices may now be falling, based on data available to the autumn of 2009.

No single figure can be quoted for the installed cost of wind farms, as much depends on the difficulty of the terrain, transport costs and local labour costs. Generation costs depend, in addition, on the wind speed at the wind farm site - since this determines the energy productivity - and on the financing parameters. The latter depend on national institutional factors which influence whether wind farm investments are seen as high or low risk. Although there is a broad consensus that wind turbines are now sufficiently reliable to enable depreciation over a 20-year period, the 'weighted average cost of capital' (WACC) may lie between 5% and 11%. (The WACC is a weighted average interest rate that takes into account the cost of both bank loans and equity investments).

Figure 10.3
Typical generation costs



Typical generation costs are shown in Fig. 10.3 above, using installed costs between US$ 1 700/kW and US$ 2 600/kW, an 8% interest rate and a 20-year amortisation period. Operating costs, which cover the costs of servicing, repairs, management charges and land leases have been set at US$ 32/kW/yr for the lower capital cost and US$ 60/kW/yr for the higher capital cost. The link between wind speed and energy productivity has been established by examining the performance characteristics of a number of large wind turbines that are currently available. Although there is not a unique link between wind speed and capacity factor, the spread is quite small. All wind speeds refer to hub height. The estimates suggest that generation costs at US$ 2 600/kW range from just under US$ 200/MWh at 6 m/s, falling to US$ 84/MWh at 9.75 m/s. At US$ 1 700/kW, the corresponding range is US$ 125/MWh to US$ 53/MWh, respectively.

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 single machines and clusters of two or three. By building wind farms, economies of scale can be realised, particularly in the civil engineering and grid connection costs and possibly by securing quantity discounts from the turbine manufacturers.

The attractions of offshore wind are the availability of a huge resource, low environmental effects and good wind speeds - often exceeding 8 m/s – which are only found on limited numbers of onshore sites. The downsides are the need to protect the wind turbines from salt spray, the higher foundation and installation costs and the additional expenses of organising operation and maintenance activities.

Offshore wind installations have been built in the waters around Belgium, China, Denmark, Germany, Ireland, the Netherlands and the United Kingdom. A number of projects are being planned in Canada and the USA. The UK Government has recently awarded concessions that allow the development of up to 32 GW of offshore wind; when this is added to awards from licensing rounds, the UK is set to host up to 40 GW in total.

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. 10.4 gives an indication of typical parameters for offshore and onshore wind farms. The strength of the offshore wind may be gauged by noting that the offshore wind farm is half the capacity of the onshore farm, but delivers well over half the energy output.

Figure 10.4
Key features of an onshore and an offshore wind farm

	Onshore	Offshore
Project name	Hadyard Hill, Scotland	Alpha Ventus, Germany
Project locations	72km south of Glasgow, in the Southern Highlands of Scotland	45km from the coast
Site features	moorland, 250m above sea level	water depth 30m
Turbines	52 x 2.3 MW	12 x 5 MW
Project rating	120 MW	60 MW
Turbine size	58 and 68 m hub height, 82 m diameter	90 m hub height, 116 m diameter (6) 92 m hub height, 126 m diameter (6)
Energy production (annual)	320 000 MWh	220 000 MWh
Construction completed	2005	2009
Source	Scottish and Southern Energy	E.ON Climate and Renewables, EWE and Vattenfall Europe

Small scale wind power

Although the largest wind turbines tend to attract most interest, there is a wide range of sizes available commercially, from small battery-charging machines with ratings of a few Watts, up to, say 100 kW for farm use. A recent review of this market (Frey, 2010) found 124 manufacturers and suggested the term ‘micro SWTs’ be used for machines up to 1 kW output, ‘mini’ up to 10 kW output and ‘midi’ up to 100 kW output. Although such turbines are relatively more expensive than their larger counterparts, they are generally not competing with electricity from large thermal power stations and may be the only convenient source of power - possibly in conjunction with batteries or diesel generators. 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 impact of wind power

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 by about 6 months or less, and so electricity generated after that time realises substantial emission savings. In many cases wind generation displaces coal-fired plant, so 1 kWh of wind saves about 0.8-1 kg of carbon dioxide.

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 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 be higher than 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, especially local planning guidelines.

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.

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.

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 wind 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 help to 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.

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 come 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 modest cost. Several studies have been reviewed by the International Energy Agency (2005). More recent estimates suggest 10% wind energy is likely to incur extra costs in the range GBP 2.5-5/MWh (US$ 4-8/MWh) and 20% wind energy in the range GBP 3-6/MWh (US$ 5-10/MWh), approximately (Milborrow, 2009). Beyond 20%, 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.

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 now forging ahead and there are plans for further capacity in Canada, the Middle East, the Far East and South America. The future rate of development will depend on the level of political support from national governments and the level of commitment, internationally, to achieving carbon dioxide reduction targets.

Projections of future capacity vary. The International Energy Agency's Reference Scenario suggests 422 GW by 2020, but other studies suggest higher values. The European Wind Energy Association suggests there will be 230 GW in Europe by 2020, of which 40 GW will be offshore. The technology has developed rapidly during the past 20 years, is still maturing and further improvements are expected both in performance and cost.

Taking the IEA's cautious estimate of 422 GW for the installed capacity in 2020 and assuming an installed cost of US$ 2 000/kW suggests investments of around US$ 522 billion will be required over the next 10 years.

Wind Energy today represents the fastest growing technology in the energy production space globally today. Energy is generated from wind in 79 countries around the world and 24 of the countries today already have installed capacity of more than 1000MW. Within the low carbon energy generation technologies, wind has emerged as the top technology of choice, investors are becoming increasingly comfortable backing wind investments and as this chapter will demonstrate, wind energy not only a mainstream energy sector but is already a global industry with large international players dominating the industry. In most parts of the world where generation sources compete on the basis of market reflective pricing of electricity, wind is beginning to offer stiff competitions to the other most preferred low fossil intensity technology gas fired CCGT technology.

The current and likely future trends in wind energy economics, investor sentiment and the strategic conduct and corporate trends in the wind industry suggest a robust belief in the future of wind energy with a forward looking perspective on emerging risks and future challenges. The chart below attempts to capture the high level messages of today's status quo.

STRATEGIC ASSESSMENT OF GLOBAL WIND ENERGY

Outlook and Growth Drivers:

- Current global installed capacity expected to grow from 282GW to approx. 750 GW by 2020. On shore and sites with lower wind speeds expected to dominate share of new build. Off shore to continue to be a niche play.
- Technology maturity, investor familiarity, high learning rates, rising average turbine ratings are key drivers of growth and are supported by a widespread trend towards low carbon electricity.
- Improvement on low wind speed technology performance will drive wind access sites
- Cost competitive gains may be off set if consolidation trends in the sector continue and global specialists emerge.
- In Off shore- early trends of cooperation between oil and gas and wind industries.

Key Growth Geographies and Source of Expertise:

- US market is expected to be the largest market by 2015 although key EU markets- Germany, UK, Southern EU countries will retain their leadership in the short-medium term.
- China already aggressively competing for global wind leadership, India ramping capacity.
- UK North Sea is already beginning to lead in the deep water off-shore space (Beatrice Field) being developed by a Canadian Oil and Gas company Talisman is the first mover. Other off-shore currently is in shallow waters of Denmark and Germany.
- Other industries esp Oil and gas, shipping and advanced manufacturing are well positioned to develop skills in the sector and capture opportunities in project engineering, development and services.

The Investment case:

- Credible growth track record and increasing technological and management sophistication emerging
- Stability of Governmental policy incentives, improving economics and bias towards carbon free electricity generation
- Global technological plays, emergence of global specialists, increasing cross border transaction activity and yet significant growth potential in regional markets
- Also, as investor comfort with wind technology grows, deployment rates and cost competitiveness is set to increase further, Wind will possibly establish it self as a renewable technology of choice

Key risks and challenges:

- As industry consolidates regional policy makers are demanding greater local content requirements.
- Supply chain discontinuities emerging as turbine manufacturing matures.
- Technical de-risking of projects esp in new offshore environments, new materials and engineering practices is as yet uncharted territory.
- Intermittency of operations, difficulties in siting and consenting regimes, grid availability and back up requirements affect economics of projects considerably- greatest threat comes from energy market design considerations.
- Policy support may move away from wind with further technological maturation in favour of other new technologies

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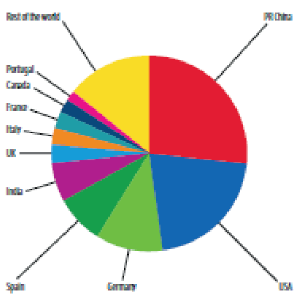
Source: Industry Publications, Expert Interviews and EnerStrat Analyses

The ongoing economic crises and the acuity of the policy uncertainty in the global energy sector, it would seem, has barely registered with the global wind energy industry. The year 2012 was a phenomenal year when the industry added 45GW of new capacity and grew at a little over 10 percent from the previous year. The slide below captures the current cumulative distribution of wind capacity across the world and the most recent capacity additions of 2012.

SNAPSHOT OF GLOBAL DISTRIBUTION OF WIND CAPACITY

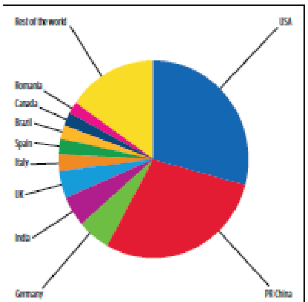
Top 10 Cumulative Capacity (December 2012)



Country	MW	% SHARE
PR China	75,324	26.7
USA	60,007	21.2
Germany	31,308	11.1
Spain	22,796	8.1
India	18,421	6.5
UK	8,445	3.0
Italy	8,144	2.9
France	7,564	2.7
Canada	6,200	2.2
Portugal	4,525	1.6
Rest of the world	39,853	14.1
Total TOP 10	242,734	85.9
World Total	**282,587**	**100.0**

Source: GWEC

Top 10 New Installed Capacity (Jan-Dec 2012)



Country	MW	% SHARE
USA	13,124	29.3
PR China	12,960	28.9
Germany	2,415	5.4
India	2,336	5.2
UK	1,897	4.2
Italy	1,273	2.8
Spain	1,122	2.5
Brazil	1,077	2.4
Canada	935	2.1
Romania	923	2.1
Rest of the world	6,737	15.0
Total TOP 10	38,062	85
World Total	**44,799**	**100.0**

Source: GWEC

US for the first time since 2009 overtaken China in annual capacity additions.

Largely as a result, OECD registered greater growth in wind capacity than Non OECD regions- again a first sine 2009.

India and China continue to lead wind capacity additions.

Source: Global Wind Energy Council 2012 Report

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It remains to be seen if this pole position that the US has wrested from China can be sustained. Tariff and fiscal incentives have played a significant part in the US wind growth story and it is unclear right now if the production tax credits- a key instrument that has contributed to wind growth in the US- will continue into 2014.

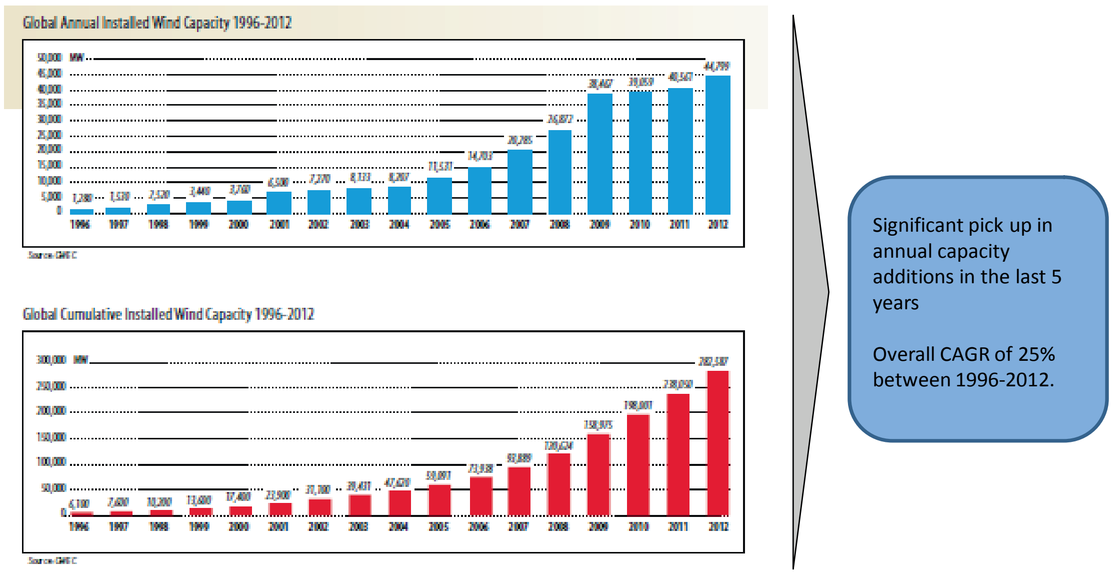
One notable aspect of the top 10 countries from the slide above is that by cumulative or new installed capacity is their dominant 85% market share. The remainder 15% (or 40GW) of cumulative or new capacity is shared by the rest of the 69 countres around the world of which the next 14 contribute more than 1GW of installed capacity implying that 55 countries around the world share the remainder 24GW of capacity. This is an important aspect not only to highlight the concentration of wind capacity while wind resources remain ubiquitous but also to suggest that these 55 countries with nearly 500MW installed capacity on an average represent the next frontier for the growth of wind energy going forward.

Understanding the Growth Trends in Global Wind Energy

Having established the growth potential for wind energy around the world, we now explore historical trends growth outlook and drivers for wind energy growth.

The slide below shows the historical observed trends in the growth of wind power capacity between 1996 -2012.

HISTORICAL GROWTH IN WIND CAPACITY



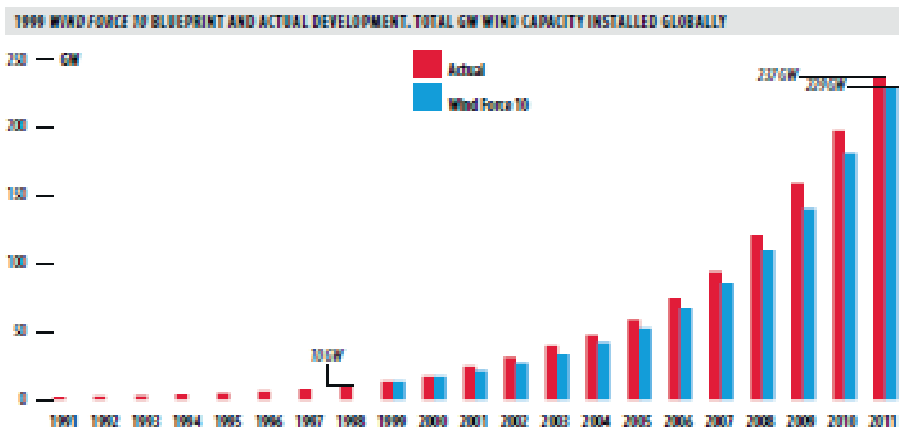
The most interesting aspect of this growth trend is that the industry has grown in the last 18 years at a cumulative average growth rate (CAGR) of nearly 25% and particularly in the last 5 years despite huge capacity additions the growth rate does not appear to be slowing down. As mentioned previously, note also that nearly 55 countries with some wind capacity are eyeing these trends and therefore the high growth rate, albeit from a low base, appears likely to be sustained.

Two key facts about the business of forecasting wind energy growth. In 2009 the IEA published an assessment of installed capacity estimates for global wind by 2030 to be 587 GW; two years later the figure of 587GW capacity appeared in as a forecast for 2020.

The first 2020 forecast of wind capacity was undertaken in 1999- when the year 2020 did indeed sound very far away. In 1999, also remember that the installed wind power capacity stood at a grand 13,600 MW and the industry was celebrating the previous year record of 2500 MW addition the previous year, the highest capacity addition in one year, ever; exuberance would have been forgiven and the group of analysts from the European Wind Energy Association, Greenpeace and Forum for Energy and Development that came together under the banner called Wind 10 published a forecast for wind capacity by 2020 at 229 GW and it was rightly labelled at the time as a "pie in the sky".

The slide below shows how actual wind power capacity development has in fact exceeded the forecast made for 2020 in 1999 on a year one year basis:

GROWTH PROJECTIONS IN OF THE WIND 10 INITIATIVE *OF 1999-THEN CONSIDERED OUTRAGEOUSLY AMBITIOUS- HAVE BEEN SURPASSED IN REALITY YEAR ON YEAR



The Wind 10 Initiative- comprising European Wind Energy Association, Greenpeace and Forum for Energy and Development- published a first 2020 forecast for Wind in 1999- which was dismissed by many analysts as a"pie in the sky".

Source: Global Wind Energy Outlook 2012

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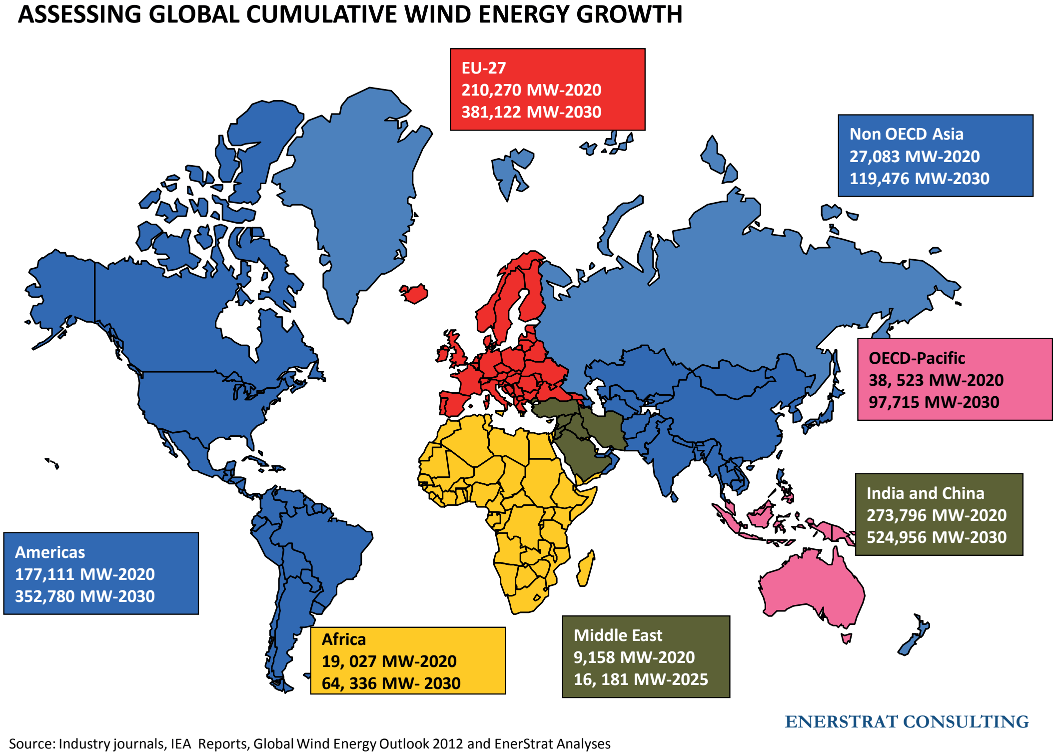
It is against the backdrop of these facts that we now explore future growth trends for wind capacity.

The slide below is based on an assessment carried out by the Global Wind Energy Council on the basis of known projects going out for the next 5 years upto 2017 and is shown broken down by annual additions expected by region. Note that by 2017, according to this assessment the cumulative installed capacity by 2017 already reaches nearly 537GW.

Also note that the installed capacity base nearly doubles by 2017 from 2012 levels for both the US and Asia (primarily driven by China) and reflects the race for global leadership already in evidence in 2012/13 between the two countries. Note also that European growth projections are slightly muted in comparison.

Based on the range of forecasts provided by the IEA in its New Policies Scenario and taking into consideration IEA's latest forecasts for 2020 at 587 GW and the range of forecasts provided by the Global Wind Energy Council and adjusting for the differences in their regional classification methodology and triangulating the actual observed and implied future growth rates developed a consensus or median growth forecasts and these are presented by region for the years 2020 and 2030 in the slide below on the next page.

As the slide suggests, we anticipate 2020 wind capacity to touch about 750GW and to double again by 2030 to about 1550GW. Note that during the period 1990-2012, wind capacity has been doubling every three years, however, the dominant growth regions in this assessment still continue to be Asia (mainly India and China), US and Europe. The bottom 55 countries still do not figure in any major way in this assessment implying that these numbers could be still possibly represent the lower end of the actual growth profile.



Growth Drivers

A number of factors is driving growth in the wind technology space. Chiefly, Wind Resource, Technology Maturity, Bankability, and an irreversible policy trajectory that incentivises investment in low carbon sources of generation –which have provided the much needed initial investment momentum for wind investments.

Wind resource all over the world is phenomenal. As mentioned in the previous version of SER 2010, the total resource around a million GW '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) that would still correspond, roughly, to the total worldwide capacity of all electricity-generating plant.

In terms of technological maturity, the average turbine rating in the 1980s was 50KW while the comparable figure in 2000 was 2MW and currently turbine sizes of 5MW and 10MW are possible. This is a huge shift in addition to the improvements in rotor and tower design that have allowed rotor diameters of 80 mtrs to be considered "standard" whereas the comparable figure in the 80s was 15 mtrs. Improvements in advanced drivetrain designs that improve reliability and reduce cost, greater production volumes, improved power electronics that allows greater frequency and voltage control in operations have all played –and continue to play- a part in enhancing the competitiveness of wind power.

As we shall see in the chapter on investment economics, learning rates and various other techniques to predict the future cost of energy from wind play an important role in understanding the growth drivers in this industry.

Offshore Wind

A total of 5,415 MW of offshore wind power has been installed globally as on today- representing about 2% of total installed wind power capacity. More than 90% of it is installed off northern Europe, in the North, Baltic and Irish Seas, and the English Channel; and most of the rest is in a number of demonstration projects off China's east coast. However, there is also great interest elsewhere: Japan, Korea, the United States, Canada, Taiwan and India have shown enthusiasm for developing offshore wind in their waters. According to the more ambitious projections, a total of 80 GW could be installed by 2020 worldwide, with three quarters of this in Europe. The table below gives a breakdown of installed off shore wind capacity by region.

Global offshore wind power in the end of 2012

	2012 (MW)	Cumulative (MW)
UK	854	2,947.9
Denmark	46.8	921
China	127	389.6
Belgium	185	379.5
Germany	80	280.3
Netherlands	0	246.8
Sweden	0	163.7
Finland	0	26.3
Japan	0.1	25.3
Ireland	0	25.2
Korea	3	5
Norway	0	2.3
Portugal	0	2
Total	**1,296**	**5,415**

One aspect of the step out in off shore wind will likely be the unlikely technological collaboration between the off-shore oil and gas industry and the wind industry. The key benefit of off shore wind farms is the higher wind velocity that is available, less turbulence, greater swept area for larger farms, fewer environmental and planning constraints and the possibility of larger scale developments. Off shore oil and gas platforms have a long established track record in operating in harsh marine environments and have the technology and resource pool that can benefit the wind industry. An early example of such a oil and gas-wind energy collaboration is the Beatrice Field Windfarm Project due to be commissioned in 2017 which has come out of a previous demonstration project started in 2007.

The Beatrice Wind Farm Demonstrator Project was a joint venture between Scottish and Southern Energy and Talisman Energy (UK) to build and operate an evaluation wind farm in the deep water close to the Beatrice Oil field in the North Sea. Built in 2007, with 2 turbines and a total capacity of 10 MW, it was designed to examine the feasibility of creating a commercial wind farm in deep water and a reasonable distance from the shore. The jacket foundation design was developed by the Norwegian company OWEC Tower AS, and fabricated in Scotland by Burntisland Fabrications. The site is 22 km from the Scottish coast and in 45m of water. The project was proposed to last 5 years. All the electricity generated is fed to a nearby oil rig.

In February 2009, the partnership of SSE Renewables and SeaEnergy Renewables, was awarded exclusivity by The Crown Estate to develop the Beatrice offshore wind farm in the Outer Moray Firth just to the north of the existing 2 demonstrator turbines. The development will cover an approximate area of 131.5 km2, consist of 184 turbines and a total capacity of 920 MW. The project is currently in the planning stage with construction starting in 2014 and fully operational by 2017.

Estimating Future Costs of Wind Energy

Within the electricity sector, particularly in the case of wind, the Levelised Cost of Energy (LCOE) is the most significant metric that impacts the value of the project to the all stakeholders including the wider society although not all societal costs are captured by the LCOE. Capital costs and operational performance are both important components that drive the LCOE. Both measures are also equally difficult to forsee long into the future however established techniques have evolved to predict with a sufficient confidence interval the future costs of energies- including wind energy.

Operational Performance Improvements:
A combination of techniques such as “learning curves”, expert elicitation and engineering modelling studies have been successfully used in the wind industry to estimate future costs. By using learning curves learning rates or percentage reductions associated with every doubling of capacity in the wind industry are calculated and these are used to forecast future costs. A recent exercise carried out for the Inter- Governmental Panel on Climate Changea range of learning rates between 9-19% has been identified to forecast suture wind costs.

Similarly, by another process called “expert elicitation” the European Wind industry and the US DoE has determined a 10% reduction in energy capital costs and a nearly 20% increase in capacity factors to be a sensible range between 2005 and 2030. Similarly the NREL modelling work has also revealed that a performance increases of almost 20% and cost reductions of 10% may be used, similar results were obtained by the European “Upwind Study” to determine future costs of a possible 20MW wind turbine.

As mentioned earlier in the chapter, the rising hub heights and increasing rotor diameters have continued to trend towards larger machines and recent analyses by NREL suggests that “capacity factors for projects to be installed with current state of the art technology will improve significantly within a given wind power class relative to older technology; importantly most significant improvements are occurring in equipments designed for low wind speeds of 7.5m/s” As result of these advances it has been found that the amount of land area that could achieve 35% or higher wind project capacity factors has increased by as much as 270% in the US when going from turbines installed during 2002-03 to current low wind speed offerings. This is a significant finding as from these flow important implications for wind projects irrespective of geography that 1) future capacity factors can be assumed to be higher upto 35% and that 2) that the number of hitherto rejected low wind velocity sites will now come into play thus offering a greater number of sites to accommodate growing capacity. The figure below is reproduced from the IEA Wind Task 26 report of 2012 that graphically illustrates the commercial materiality of these findings:

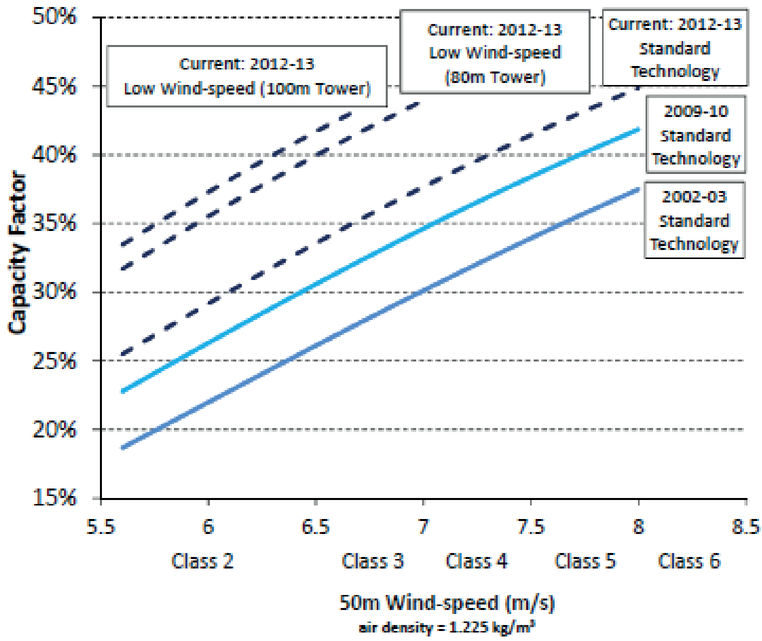
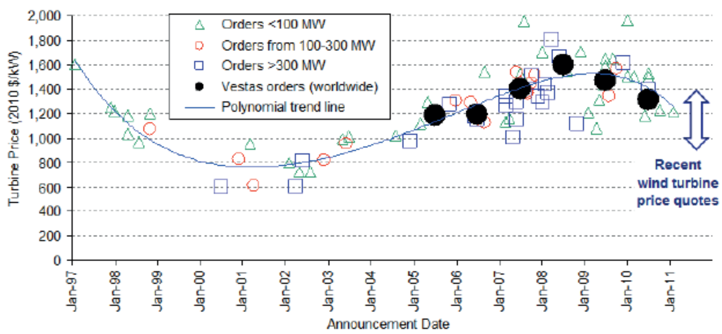


Figure 7. Modeled capacity factors for current turbine models relative to historical technology

Source: Wiser et al. 2012

Capital Cost Improvements:

WIND TURBINE PRICE TRENDS 1997-2012



Source: Bolinger and Wiser 2011

- The years 2005-2009 were years of tight turbine supply, which now appears to be easing as new manufacturing facilities come on stream and new players emerge esp in the emerging markets in China and India.

- No clear trend of bargaining power of larger (greater than 300MW project orders) developers appears evident, a new "standard" turbine specification appears to be emerging. This standardisation will likely yield further lower prices if industry consolidation slows down providing opportunities for lower project level capex.

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Source: Original Bolinger and Wiser Study quoted in NREL February 2012 Report and NREL own global data set for 2011/12 WTG prices.

As the slide above shows, largely as a function of new manufacturing capacity turbine prices and therefore project capital costs have recently declined since their peak in late 2000s and as a result of continual improvements in turbine technology are expected to result in possibly historic lows in the LCOE of wind particularly in low and medium wind speed sites- 6.0m/s to 8.5m/s.

Applying the above performance measures and projected capital costs the IEA Task 26 working group has obtained results for the LCOE of Wind going forward that is shown in the graphic below.

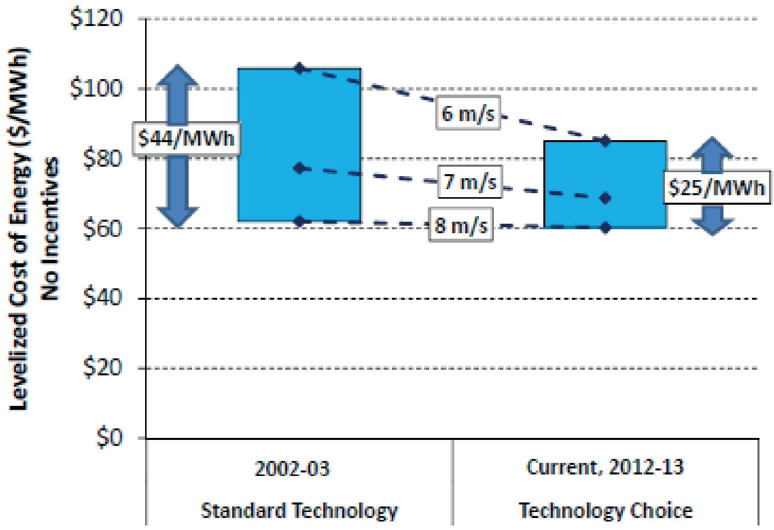
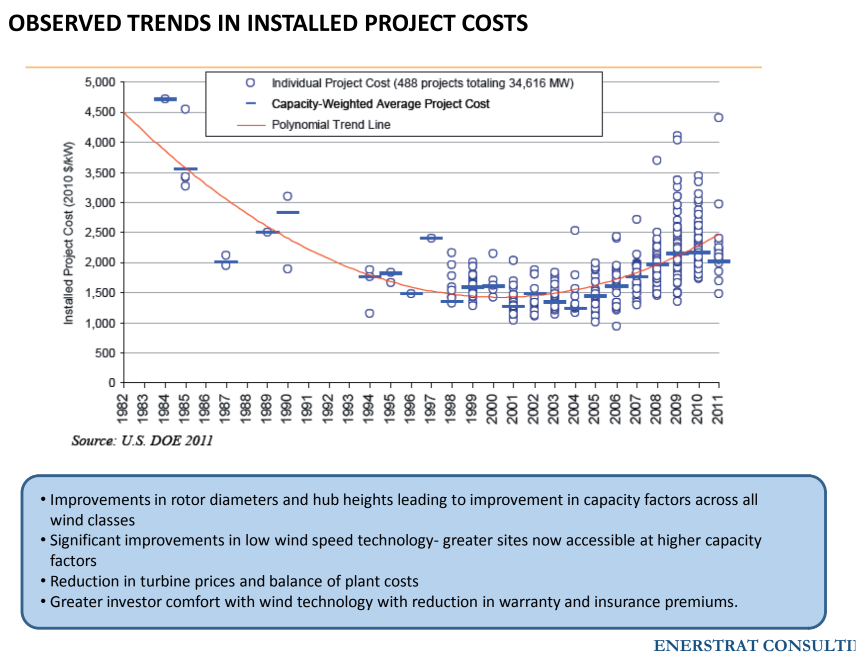


Figure 10. Estimated change in the LCOE between low and high wind speed sites resulting from technological advancement

Source: Wiser et al. 2012

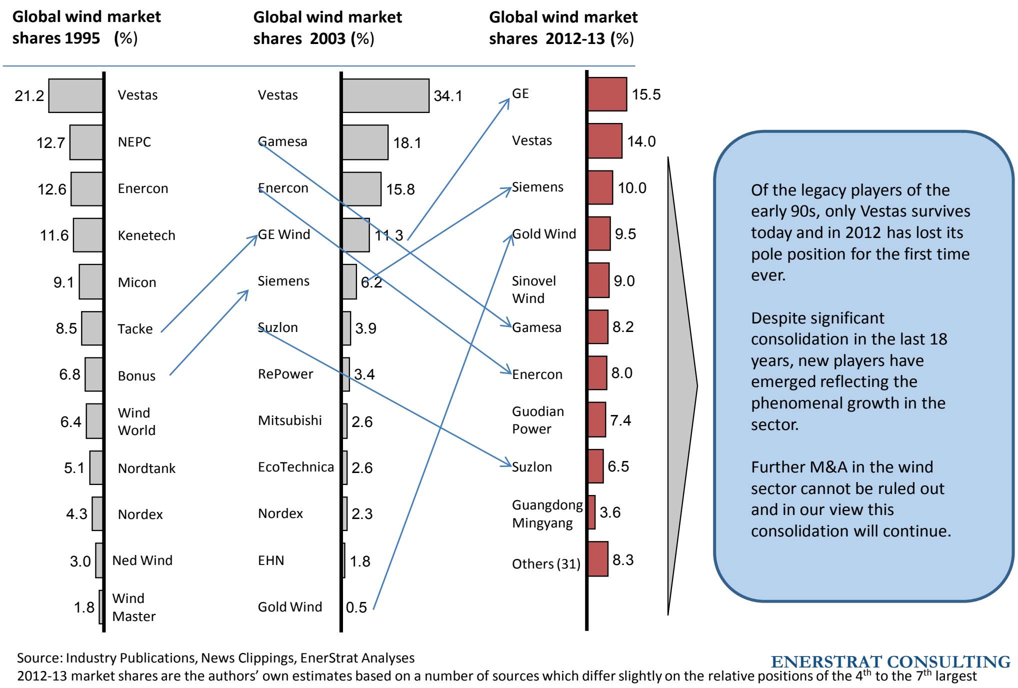
Additionally, the slide below provides a graphical illustration of how the above described factors are leading to a better understanding of project capital and performance metrics and as a result a growing comfort with wind power for current investors and possibly will attract new investors into this space.



Strategic Trends and Industry Outlook

In this final section of the chapter we now focus on the evolving structure and strategic conduct of the wind industry so far. The slide below captures the observed trends in the market shares of players at key points in the industry's history:

GLOBAL CORPORATE ACTIVITY IN WIND 1994-2012/13



Source: Industry Publications, News Clippings, EnerStrat Analyses
2012-13 market shares are the authors' own estimates based on a number of sources which differ slightly on the relative positions of the 4th to the 7th largest player in the Industry

In 1995 the top 4 players in the industry comprising 12 players controlled a 60% market share and the size of the industry in MW terms was all of 6100MW thus leading to a median size of a company around 500MW. Of the companies in 1995, Kenentech declared bankruptcy, Enron bought Tacke and was itself subsumed eventually by GE whereas the four smaller companies Micon, Wind World, Nord Tank and Ned Wind merged to form NEG Micon which eventually was acquired by Vestas leading to a jump in the market share for Vestas by the time the acquisitions were completed in 2003.

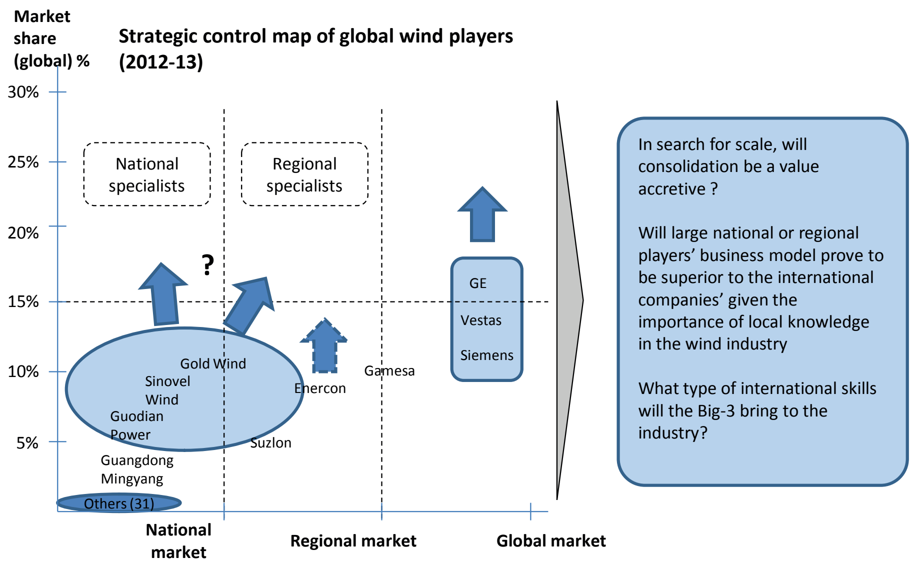
Not only is this a story of rapid consolidation and emergence of global players like GE and Siemens in the top 3 by 2012 but it is also a story of aggressive growth- by 2003 while the number of players remained constant despite the consolidation as new players like Gold Wind of China and Suzlon of India emerged on the scene, the installed capacity of the industry was 39.5GW raising the size of the average player from 500MW in 1995 to 4000MW by 2003 and to a whopping 7100MW by 2012. Wind industry has finally built itself to a global scale.

In 2003 the top 4 players now controlled a whopping 80% of the market share while by 2012, with the emergence of national and regional specialists the industry concentration had come back to 1995 levels where the top 4 companies now control 50% of the market share. This means that for the top 4 companies the average asset portfolio size is now over 35GW- comparable to some of the largest global utility players.

What does this portend for the future? Our assessment is that the next three years (when the next survey will be written, the industry will go through further rounds of consolidation. Note that today nearly 31 smaller, sub-scale companies make up a combined 8% market share. As the global players vie for industry leadership the competition for assets is expected to rise, driving higher valuations though given that the next phase of growth may come from emerging economies of India (already the fifth largest country with wind installations) and China (which already has built local companies with global scale) it remains to be seen if the large international players will be able to maintain their leading positions.

The slide below is a strategic control framework that describes the competing route maps to global leadership in wind.

LIKELY GROWTH VECTORS FOR THE GLOBAL WIND INDUSTRY



Source: EnerStrat Analysis

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Challenges to the industry over the next 3 years

The wind industry faces three main challenges in the near-medium term:

1. Balancing the demands of globalisation with increasing demand for local content requirements will challenge the business models of the wind industry

   Local Content Requirement (LCR) refers to a government requiring companies operating in its jurisdiction to source all or part of the components required from local manufacturers. This sits at cross purposes with the intergrated global supply chains that will be required to be built to sustain benefits of scale economies.

   Furthermore, policy makers, particularly in smaller countries, will find the prospect of introducing renewable energy along with jobs growth tantalising.

   The recent example of Brazil introducing LCR appears to hold a possibility of a slow down in the uptake for renewable energy.

2. As the industry becomes globally competitive the fiscal and policy/tariff support it currently enjoys may come under pressure.

   There is currently no evidence for this but the finite pool of funds that might have to be distributed across the renewable energy technologies, many of which are not as well developed as wind, globally does pose considerable risk.

3. The issue of how large scale wind gets integrated into a national generation mix- especially how newly competitive wind technologies stand up the interfuel competition especially from gas fired generation capacity with which it will certainly compete in most geographies.

   In most electricity markets, where gas fired power generation assets operate along with wind assets, gas capacity is increasingly viewed as a backup to compensate for the no-availability of wind capacity. Typically in the Northern hemisphere, where energy demand shoots up on a cold anti-cyclonic day, it is gas fired generation that is called in to supply. Thus relative to gas assets the delivery risk factor of wind assets is greater. The outlook for wind in such circumstances would be predicated upon the market design and pricing mechanisms in the local market.

In conclusion, the wind industry has before it tremendous opportunities for growth but equally daunting are the challenges it faces within and without. Will the wind industry live up to its projections- as it has done thus far for the last two decades- or will this be a different story this decade?

Ashutosh Shastri
Director, Enerstrat Consulting UK

Global tables

Country	“Installed capacity” MW	Annual Output GWh
Albania	42.00	
Algeria	0.10	
Argentina	142.50	450.00
Armenia	2.64	
Australia	2226.00	
Austria	1084.00	1934.00
Azerbaijan	2.00	
Bahrain	1.00	
Bangladesh	2.00	
Belarus	3.50	
Belgium	1078.00	
Brazil	1426.00	2705.00
Bulgaria	539.00	861.00
Canada	5265.00	13800.00
Cape Verde Islands	38.00	
Chile	190.00	
China	62364.30	73200.00
Colombia	18.00	41.30
Costa Rica	148.20	
Croatia	129.75	201.00
Cuba	12.00	
Cyprus	134.00	
Czech Republic	219.00	397.00
Denmark	3927.00	
Dominican Republic	34.00	
Ecuador	3.00	
Egypt	550.00	
Eritrea	1.00	
Estonia	181.00	368.00
Ethiopia	52.00	
Faroe Islands	4.25	
Finland	199.00	481.00
France	6549.40	12100.00
Germany	29071.00	48883.00
Greece	1749.00	117.00
Guadeloupe	26.00	
Guyana	14.00	
Hong Kong	0.80	
Hungary	329.40	
India	15880.00	19475.00
Indonesia	0.93	4.69
Iran	91.00	
Ireland	1738.00	
Israel	6.00	
Italy	6936.10	9856.00
Jamaica	48.00	

Japan	2294.00	4016.00
Jordan	1.90	
Kazakhstan	1.50	0.00
Kenya	5.00	
Korea (Republic)	425.00	
Latvia	30.00	70.00
Libya	20.00	
Lithuania	179.00	
Luxembourg	45.00	
Macedonia	0.00	
Martinique	1.00	
Mauritania	0.00	
Mauritius	0.00	
Mexico	570.00	1300.00
Mongolia	1.30	
Montenegro	0.00	
Morocco	291.00	
Netherlands	2328.00	
New Caledonia	28.00	
New Zealand	622.90	
Nicaragua	102.00	
Niger	2.20	
Nigeria	2.00	
Norway	520.00	
Pakistan	6.00	
Peru	1.00	
Philippines	33.00	
Poland	1799.93	3204.55
Portugal	4336.00	9162.00
Réunion	15.00	
Romania	821.80	1149.00
Russian Federation	15.40	
Slovakia	3.00	
South Africa	10.10	
Spain	21673.00	41790.00
Sri Lanka	14.00	
Swaziland	45.50	
Sweden	2900.00	6100.00
Switzerland	45.51	70.13
Syria	0.60	
Taiwan	564.00	
Thailand	7.28	
Tunisia	104.00	
Turkey	2063.70	5700.00
Ukraine	151.00	
United Kingdom	6488.00	
United States of America	46919.00	120177.00
Uruguay	43.50	
Venezuela	30.00	
Vietnam	31.00	
Total World	**238048.99**	**377612.67**

Country notes

Australia

Wind energy continues to increase its stake in Australia's clean energy mix following another year of growth in 2012. Wind energy now makes a significant contribution to Australia's energy mix, supplying over 7,700 GWh annually. This equates to around 3.4% of the nation's overall electricity needs and the equivalent of more than one million average Australian households.

Australia's 20% by 2020 Renewable Energy Target (RET) continues to provide the greatest incentive for the development of wind energy in Australia and has driven installed wind capacity from approximately 71 MW in 2001 to 2,584 MW as at the end of 2012. The RET is now complemented by Australia's carbon price mechanism, which commenced on 1 July 2012 with the aim of reducing emissions in the stationary energy sector.

Austria

With nearly 70% of renewable energy in its electricity mix, Austria is among the global leaders in this respect. Without any doubt, it is the natural conditions in Austria—hydropower, biomass, and a high wind energy potential—that allowed such a development. Due to the new Green Electricity Act (GEA 2012) (Ökostromgesetz 2012), annual wind power installations in Austria increased to 296 MW in 2012. This represents an annual growth rate of 27% compared to the previous year.

By the end of 2012, nearly 1,400 MW of wind power was operating in Austria. An additional 420 MW of wind power will be constructed in Austria in 2013

Canada

Canada is the ninth largest producer of wind energy in the world. It has more than 6 GW of wind energy capacity, which produces enough power to meet about 2.8% of the country's total electricity demand. Canada has more than 170 wind farms, spread across ten provinces and two territories.

In 2012, Canada placed ninth globally, in terms of new wind energy capacity installed. Nearly 940 MW of new wind capacity were installed in six provinces and one territory. The province of Quebec led the way, with 430 MW of new installations. The world's most northern large-scale wind-diesel hybrid power facility was commissioned in Canada's Northwest Territories.

The government of Canada continues to fund the growth of Canada's wind power sector through its ecoENERGY programs. Provinces across Canada continue to offer a range of incentives for renewable power, including wind. In some cases, existing programs have or will undergo reviews and changes. Ontario, for example, completed a scheduled two-year review of its Feed-in Tariff (FIT) program. A rate reduction in the price paid for wind generated electricity was one of several recommendations put forward, as a result of the review. In Nova Scotia, a review of the province's Community FIT (COMFIT) program is under way.

Community power was given a boost in 2012 with the approval of 46 community projects under Nova Scotia's COMFIT program. The projects range in size from 50 KW–6 MW, and are located in over 40 different communities across Nova Scotia. In Ontario, the M'Chigeeng First Nation Band celebrated the grand opening of its 4-MW Mother Earth Renewable Energy (MERE) wind farm in northern Ontario. MERE is Ontario's first wind farm owned entirely by a First Nation Band.

China

In 2012, 12,960 MW of new wind capacity was installed in China, increasing the accumulated capacity to 75,324.2 MW. During the year, wind power generated 100.4 TWh of electricity replacing nuclear power as the third largest electricity source in China. But compared to conventional power, wind power only accounted for 2% of generation, so there is a high potential for growth. In the future, wind power could and should play a more important role in the clean and sustainable energy and electricity supply.

After years of rapid development, China's wind power industry has entered an adjustment period and development has slowed. The industry has shifted from expansion of quantity to the improvement of quality. The government and enterprises are paying attention to improving the quality of the Chinese wind power industry. In 2012, grid integration and consumption were the most important bottlenecks that restrict China's wind power development. The government is taking policy, management, and technical measures to overcome these problems.

Germany

Wind energy continues to be the most important renewable energy source in Germany in medium term. Within the German federal government, the Federal Ministry for the Environment, Nature Conservation, and Nuclear Safety (BMU) is in charge of renewable energy policy as well as of the funding of research for renewable energies.

The share of renewable energy sources in Germany's gross electricity consumption rose significantly in 2012 to reach 22.9%. This represents an increase of nearly two and a half percentage points against the previous year (20.5%). At 136 billion kWh, electricity generation from solar, wind, hydro, and biomass was around 10% higher than in 2011. This upward trend was largely due to the sharp increase in electricity generation from photovoltaic systems. Biogas was another growth area, and generation from hydropower increased from the previous year due to high rainfall.

Relatively poor wind conditions led to a decline in electricity generation from wind (2012: 46 TWh; 2011: 48.9 TWh) despite of the fact that 2012 also saw a strong upward trend in the expansion of wind energy capacity, and 675 MWh were generated by offshore wind. Construction of new turbines added 2,440 MW, a clear increase from the previous year (2,007 MW). Repowering measures accounted for 541 MW, while installations with a capacity of 196 MW were dismantled, giving a net capacity in 2012 of 2,244 MW. At the end of the year total installed wind capacity in Germany was nearly 31,315 MW, of which 280 MW were offshore.

Greece

In 2012, 117 MW of new wind capacity were installed in Greece the total installed wind capacity is 1,749 MW, a 7% increase from 2011. There are 121 wind farms in Greece. Almost 150 million EUR (197 million USD) was spent in the wind energy industry in 2012.

The Hellenic Wind Energy association (HWEA) still expects roughly 150 MW of new capacity could be added in Greece in 2013 after capacity increased 117 MW to 1,746 MW in 2012. The pace of installation must increase to reach the 2020 target of 7,500 MW of wind capacity as included in the national renewable energy action plan.

The government has many issues to consider in reaching this target. As part of a package of austerity measures approved in November 2012, wind and other renewable producers will be charged a 10% extraordinary tax on revenues for 12 months, dated back to 1 July 2012.

Denmark

Approximately 23.7% of Denmark's energy consumption came from renewable sources in 2012, 38.3% from oil, 19.4% from natural gas, and 13.8% from coal. The production from wind turbines alone corresponded to 30% of the domestic electricity supply, compared to 28.2% in 2011. The total domestic supply was nearly the same in 2012 as in 2011.

Wind power capacity in Denmark increased by 210 MW in 2012, bringing the total to 4,162 MW (Table 1). There were 220.6 MW in new turbines installed while 10.7 MW were dismantled. Most of the installed wind turbines in 2012 were onshore, while 14 of the 111 planned 3.6-MW turbines were installed offshore in the Kattegat project Anholt. The largest rated turbine to be installed in 2012 was the 6-MW Siemens turbine at the Oesterild Testsite.

Finland

In Finland, 32% of electricity consumption was provided by renewables in 2012. Finland's generating capacity is diverse. In 2012, 26% of gross demand was produced by nuclear, 20% by hydropower, 27% from combined heat and power (coal, gas, biomass, and peat), 7% from direct power production from mainly coal and gas, and 20% from imports. Biomass is used intensively by the pulp and paper industry, raising the share of biomass-produced electricity to 12% in Finland. The electricity demand, which is dominated by energy-intensive industry, was 85 TWh in 2012.

Finland aims to increase the share of renewables from 28.5% to 38% of gross energy consumption to fulfill the EU 20% target by 2020. The national energy strategy foresees biomass as providing most of the increase in renewables. Wind power is the second largest source of new renewables in Finland, with a target of 6 TWh/yr by 2020. The new energy strategy set a target of 9 TWh/yr for 2025.

A market-based feed-in system with a guaranteed price of 83.50 EUR/MWh (110.05 USD/MWh) entered into force in 2011. There will be an increased tariff of 105.30 EUR/MWh (138.80 USD/MWh) through the end of 2015. The difference between the guaranteed price and spot price of electricity will be paid to the producers as a premium.

Korea, Rep.of

The cumulative installed wind power in the Republic of Korea was 406 MW in 2011 and 487 MW in 2012, increasing by 17% from the previous year. Most wind turbine systems installed in 2012 were supplied by local turbine system manufacturers. A Renewable Portfolio Standard (RPS) proposal for new and renewable energy was enacted in 2012. The required rate of RPS in 2012 was 2% and will increase to 10% by 2022. In 2012, the first year of RPS, more than 60% of the target rate was achieved. A nine-year plan for construction of a 2.5-GW offshore wind farm off the west coast was announced in 2010. The first stage of the project, construction of 100-MW wind farm, was initiated in 2011 and is in progress.

The 2.5-GW offshore wind farm construction and RPS are expected to accelerate the growth of wind energy in Korea. Since 2009, the government has concentrated on developing Korean production of components to secure the supply chain for wind projects. More government R&D budget has been allocated to localize component supply and develop Ireland's official commitment to achieving ambitious 2020 renewable electricity targets primarily from wind power remained unchanged in 2012. A significant challenge in 2012 was the proposed implementation of arrangements for curtailment of wind farms. The associated market uncertainty may have contributed to the relatively low new wind capacity addition of 153 MW. This is below the estimated 200 MW/yr required to deliver upon the 2020 targets.

Italy

Although production capacity increased (slightly), wind energy output in 2012 did not exceed 2011 levels. Installation of new wind farms in Italy slowed its pace in 2010. Total online grid-connected wind capacity reached 5,797 MW at the end of the year, with an increase of 948 MW over 2009. As usual, the largest development took place in the southern regions, particularly in Apulia, Calabria, Campania, Sardinia, and Sicily. In 2010, 615 new wind turbines were deployed in Italy and their average capacity was 1,541 kW. The total number of online wind turbines thus became 4,852, with an overall average capacity of 1,195 kW. All plants are based on land, mostly on hill or mountain sites.

Japan

The 2010 production from wind farms could provisionally be put at about 8.4 TWh, which would be about 2.6% of total electricity demand on the Italian system. In 2012, the total installed wind capacity in Japan reached 2,614 MW with 1,887 turbines, including 25.3 MW from 15 offshore wind turbines. The annual net increase was 78 MW. Total energy produced from wind turbines during 2012 was 4.5 TWh, and this corresponds to 0.54% of national electric demand (861 TWh).

In response to the great East Japan earthquake and tsunami of March 2011, the decision was taken to dismantle four nuclear power plants in FukushimaThe cumulative installed wind power in the Republic of Korea was 406 MW in 2011 and 487 MW in 2012, increasing by 17% from the previous year. Most wind turbine systems installed in 2012 were supplied by local turbine system manufacturers. A Renewable Portfolio Standard (RPS) proposal for new and renewable energy was enacted in 2012. The required rate of RPS in 2012 was 2% and will increase to 10% by 2022. In 2012, the first year of RPS, more than 60% of the target rate was achieved.

Mexico

During 2012, 645 MW of new wind turbines were commissioned in México, bringing the total wind generation capacity to 1,212 MW. The Law for Renewable Energy Use and Financing of Energy Transition (enacted in November 2008) is successfully achieving its main objectives. Wind energy is now a competitive option within the Mexican electricity market, and the Secretariat of Energy issued a Special Program for the Use of Renewable Energy. A 2000-MW, 400-kV, 300-km electrical transmission line was commissioned for wind energy projects in the Isthmus of Tehuantepec. Presently, the construction of 276 MW of new wind power capacity has been secured. This will bring the total generation capacity to at least 1,488 MW by the end of 2013. It is expected that public and private companies will be capable of managing appropriately pending social requirements. In 2012, 195.3 MW of new wind power capacity was installed in Norway, which is more than has ever been installed in one year before. Total installed capacity was 704 MW at the end of the year and production of wind power in 2012 was 1,569 GWh compared to 1,308 GWh in 2011.

Norway

The calculated wind index for Norwegian wind farms in 2012 was 103%, corresponding to a production index of 107%. The average capacity factor for Norwegian wind farms in normal operation was 31.2%.Wind generation amounted to 1.1% of the total electric production in the country.

Portugal

In Portugal, 2012 was an atypical year in Portugal with regards to energy. Due to the efficiency measures implemented in recent years, but also due to the economic recession, electricity consumption in Portugal dropped 3.6% to 49.1 TWh. This represents a reduction of 6% of electricity demand in the last two years. It was also an extremely dry year, the fifth driest hydro year of the past 80 years (63% below the normal climate). Therefore, due to the reduced hydro production, the renewable contribution for the energy mix decreased 17% compared to 2011.

Spain

Installed wind capacity in Spain reached 22,785 MW in 2012 with the addition of 1,112 MW, according to the Spanish Wind Energy Association's (AEE) Wind Observatory. The growth has been similar to 2011, which had an increase of 1,050 MW. Spain is the fourth country in the world in terms of installed capacity and produced 48,156 GWh of electricity from wind in 2012.

In 2012, Spain's electrical energy demand decreased 1.8% from 2011 to 269.16 TWh. Wind energy met 17.8 % of this demand and was the third largest contributing technology in 2012. Other big contributors to the system were nuclear power plants (22.2%), coal (19.8%) and gas combined-cycle power plants (13.9%) .

During 2011, the government implemented new decreases to incentives for wind energy so that the wind sector would share the burden of helping the country to reduce its subsidy bill for green energy. Spain's landmark renewable energy law, 661/2007, only governs wind power prices for new projects through 2012. A draft decree sent to the national energy commission in September sets out the proposed regulations after 2012. However, lobbyists are arguing that the 2020 target will not be achieved if the bill is passed.

Sweden

The new wind energy installations in 2012 had a capacity of 755 MW (765 MW were installed in 2011). The goal is to increase renewable generation by 25 TWh compared to the level in 2002 by 2020. A major part of wind power research financed by the Swedish Energy Agency is carried out in the research programs Vindforsk III, Vindval, and the Swedish Wind Power Technology Center (SWPTC). The technical program Vindforsk III runs from 2009–2012 and has a total budget of about 80 million SEK (9.3 million EUR; 12.3 million USD). Vindval is a knowledge program focused on studying the environmental effects of wind power.

Vindval runs from 2009–2012 with a budget of 35 million SEK (4.1 million EUR; 5.4 million USD). The SWPTC at Chalmers Institute of Technology runs from 2010–2014 and has a total budget of 100 million SEK (11.6 million EUR; 15.4 million USD). The center focuses on complete design of an optimal wind turbine, which takes the interaction among all components into account

Switzerland

By the end of 2012, 32 wind turbines of considerable size were operating in Switzerland with a total rated power of 49 MW. These turbines produced 88 GWh of electricity. Since 1 January 2009, a cost-covering feed-in-tariff (FIT) for renewable energy has been implemented in Switzerland . This policy in promoting wind energy led to a boost of new wind energy projects. Financing is requested today for additional 3,343 GWh under the FIT scheme. Due to continuous obstacles in the planning procedures and acceptance issues, only two new turbines with a rated power of 3.9 MW were installed in 2012

The United Kingdom (UK) has approximately 40% of Europe's entire wind resource and significant potential for both onshore and offshore wind. The UK government has put in place a range of measures to enable the deployment of that potential resource and is committed to ensuring the further growth of wind generation in the UK. The UK signed up in 2009 to a European Union (EU) target of 20% of primary energy (electricity, heat, and transport) from renewables sources. The UK contribution to that target is 15% by 2020. Wind will be an important contributor to this target. Figure 1 shows Griffin wind farm near Perth, Scotland, completed in 2012 with a total installed capacity of 156.4 MW. In 2012, total wind capacity in the UK was 8.29 GW, representing approximately 6% of the UK's national electricity demand, an increase of 1.8 GW from the 2011 figure (a 27% increase). A significant increase in electricity generation from wind was seen in 2012 in the UK, from 15.5 TWh in 2011 to 21.8 TWh in 2012 (40% increase)

United States of America

In the United States, 13,131 MW of wind power capacity came online in 2012, more than any other year and nearly twice as much as was installed in 2011. This added wind capacity represented 43% of new U.S. electricity generation capacity for 2012, surpassing the 33% of new generation represented by natural gas.

Wind energy now accounts for nearly 3.5% of national electricity consumption in the United States and is deployed in 39 states and territories. The state of Texas alone has more installed wind power than all but five countries around the world.

The record installations in 2012 represented a rush to complete projects before the pending expiration of a key federal incentive for wind energy—the Production Tax Credit (PTC). In January 2013, as part of the American Taxpayer Relief Act of 2012, the U.S. Congress extended the incentive for one year and changed the eligibility requirement so that rather than being in operation, farms must be under construction by the end of the year.

11

Marine Energy

Contents

Strategic insight

1. Introduction

WEC's Survey of Energy Resources (2010) provided a comprehensive commentary on Marine Energy under three separate sections:

- Tidal Energy
- Wave Energy
- Ocean Thermal Energy Conversion (OTEC)

It is perhaps symptomatic of a certain lack of progress in the development of these technologies over the intervening three years that this update is considerably shorter than its predecessor. There have indeed been definite advances but also a realisation that the deployment risks in many of these technologies have been underestimated.

Technology developers in all of these sectors have been constrained primarily by a shortage of capital and, in particular, by reluctance on the part of investors generally to commit to the significant level of capital necessary to demonstrate commercial feasibility.

Factors influencing investors include but are not limited to:

- The intensifying of the Global Financial Crisis (GFC), particularly the weakening of confidence in the Eurozone. This has led to a fall in energy demand in many developed countries and significant generation overcapacity in some.
- The major reassessment of global fossil fuel resources following the unprecedented success of shale gas production in the United States.
- The failure of successive developed country governments to properly price carbon in the primary energy fuel mix. The recent collapse of the EU Emissions Trading System (ETS) is but the latest failure in this rather sorry saga.
- The large losses suffered by investors in "Green Tech" as governments under financial strain arbitrarily cut back on financial supports —the removal by the Spanish government of subsides to the solar industry being a particularly apposite case in point.

Against this background it is not surprising that investors remain slow to commit capital to high risk marine technologies and prefer to wait until the energy industry generally settles into some new equilibrium with a lower level of investment risk.

Despite the foregoing, some notable investments have taken place.

Some utilities have provided financial support to developing new technologies although more on a project by project basis rather than through direct investment in the technologies. It is probably fair to say that most utilities do not perceive technology development to be a mainstream company activity and many of those that have become in involved in technology development have done so in response to a certain amount of political pressure.

It is therefore the involvement of either Original Equipment Manufacturers (OEMs) or Engineering Procurement and Construction (EPC) companies that is key to the development of the sector. Major milestones in this respect include:

- The purchase by Siemens AG of Marine Current Turbines (MCT) (Tidal Energy)
- The Purchase by DCNS SA of 57.9% of Open Hydro (Tidal Energy)
- The acquisition by Andriz Hydro of Hammerfest Strom (Tidal Energy)
- The acquisition by Alstom of Tidal generation Ltd. From Rolls Royce. (Tidal Energy)
- The investment by ABB in Aquamarine Power (Wave Energy)

The foregoing list is not exhaustive but clearly indicates that Tidal Energy in the form of tidal stream is maturing with Wave Energy some years behind but beginning to gain traction with investors.

OTEC continues to struggle to raise the necessary investment capital for commercial scale projects but recent announcements would appear to indicate a much improved investment climate for the technology.

2. Tidal Energy

The development of tidal energy has a long history. Tidal barrages and lagoons to power small mills have been used in Europe for many centuries. One of the important limitations on tidal technology development is its site specificity. This will always constrain tidal technology (much as site availability constrains hydroelectric technology) and limits its total potential to a fraction of what might be achieved from other marine technologies (Wave Energy and OTEC)

Barrages and Lagoons

Early modern developments in tidal energy focussed on barrage type arrangements such as that at La Rance in France. Many technically suitable sites exist for such developments worldwide. However, only a limited subset is close to centres of high demand thus facilitating transmission.

The Severn Estuary in the UK is typical of such sites and proposals for its development have been advanced on many occasions in the past. However it is becoming increasingly obvious that the likely environmental impact associated with such a development are not acceptable to the general public.

The environmental impact issue will continue to dominate barrage and lagoon type proposals and, at least in the developed world, will greatly constrain such developments.

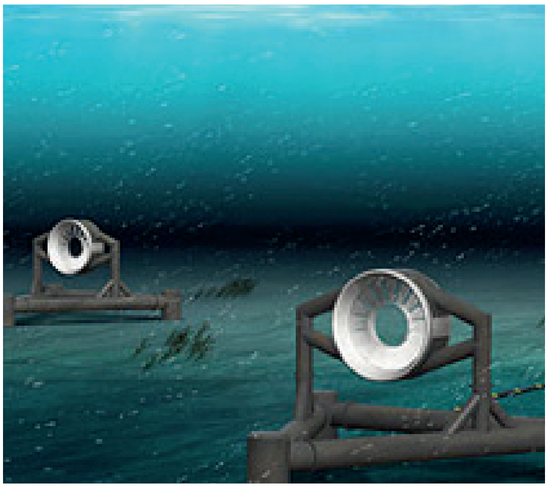
Tidal Current technologies

In contrast to the foregoing, Tidal Current technology continues to make impressive strides and is, at the moment, the leading marine technology. The following sections detail some of the advances made by selected companies in the Tidal Current technology area in the recent past.

Open Hydro

Based in Greenore on the East Coast of Ireland, Open Hydro has developed an open centre turbine and a deployment strategy which aims to put the turbine in position close to the sea floor in a very short time. The company has developed a specialised deployment vessel and

16m turbine being placed onto a deployment vessel at Brest, France



has successfully deployed and recovered turbines in extreme conditions at the Bay of Fundy in Canada.

DCNS, a French naval engineering company has recently acquired a controlling interest in Open Hydro and the company is engaged in deploying the technology off the North Coast of France. EDF, the utility customer, has committed €40m to an initial project which will see the installation of 4 X 2MW units each 16m in diameter.

Marine Current Turbines (MCT)

MCT's SeaGen system consists of twin power trains mounted on a crossbeam. The cross beam can be raised above the water for routine maintenance by winching it up a monopole support structure.

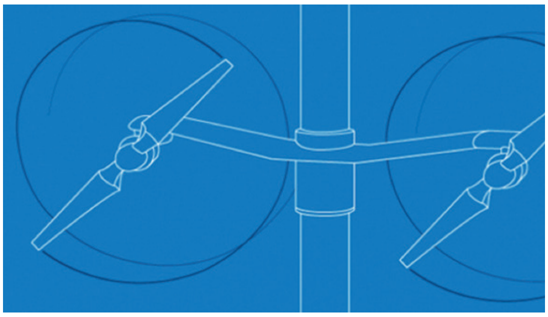
The turbines have a patented feature by which the rotor blades can be pitched through 180 degrees, allowing them to optimise energy capture and operate in bi-directional flows.

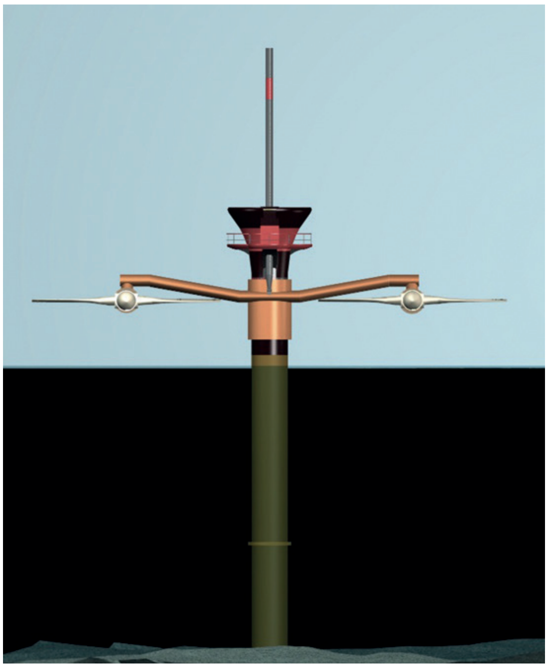
The rotors are positioned in the top third of the water column where tidal currents are strongest, therefore maximising the energy capture. The first test unit was deployed at Strangford Lough in Northern Ireland in 2008.

Siemes AG acquired a minority stake in MCT in early 2010 and subsequently achieved majority control in early 2012.

Marine Current Turbines is focused on the development of the first tidal array projects in the UK located at selected sites that will deliver an adequate commercial return for investors. The company states that a number of sites, suitable for the SeaGen technology, have been identified and initial work has already been undertaken in developing projects at these locations (see illustrations overleaf).

MCT is focussed on the supply of the technology to projects as well as coordinating maintenance during operation. Project-specific companies have been established for each of the sites to act as the developer with the intention being that investors in the SPV companies will take the projects forward.





SeaGen S

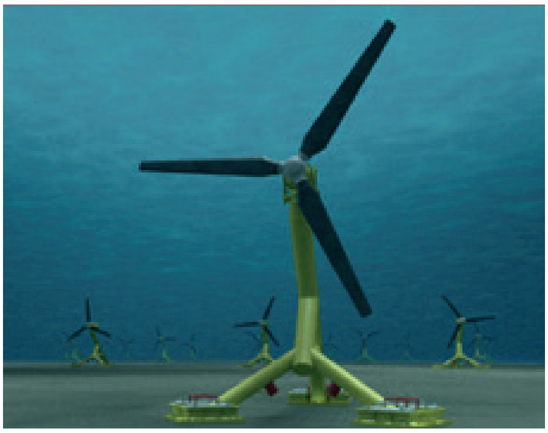
The blades and nacelle of the HS1000 tidal turbine in transportation to the European Marine Energy Centre in Orkney

The substructure of the HS1000 tidal turbine on its way from the Arnish Yard near Stornoway, where it was constructed, to Orkney.

Andritz Hydro Hammerfest (previously Hammerfest Strom)

The company has developed a technology focussed on rapid deployment and sitting relatively low in the water column as illustrated.

Its 1MW unit has been operating at the EMEC test site in Orkney since early 2012.



Summary.

Tidal Stream technology has made considerable progress over the past three years and commercial scale development is now well in sight. Costs remain high pending the deployment of larger scale projects but there is considerable optimism on the part of investors that these costs can be driven down to competitive levels.

3. Wave Energy

One of the main attractions of wave energy capture over tidal stream technology is the size of the resource. It is at least an order of magnitude greater than tidal stream. Despite this, it is not an easy technology to commercialise and a number of failures over the past decade have shown just how easy it is to underestimate the difficulties associated with designing a robust wave energy converter (WEC) given the extreme conditions to which it may be exposed.

It is reported for example that the average annual energy per metre of wave off the West coast of Ireland is approximately 40kW. This is the primary energy input and the WEC has to be designed as economically as possible to produce the maximum average output. However in a major Atlantic storm this energy is reported to exceed 4MW/metre on an instantaneous basis and this is the energy that the device has to survive if it is to remain operational.

Survivability thus becomes critical and various designs seek to maximise this while retaining reasonable efficiency characteristics.

It is an inescapable fact that WECs must be deployed in areas of high wave energy if they are to be economic. This high energy environment is often coupled with short weather windows for the safe operation of vessels. Deployment risks and costs often dominate and there are inescapable economies of scale in both the size of individual units and the size of projects if the technology is to reach commerciality. Such size implies heavy capital expenditure and considerable investment risk.

The foregoing lessons have been learned however and robust WECs are now coming off the drawing board and into the sea.

There is as yet no “standard” wave technology concept. Wikipedia for example lists 22 separate concepts at various stages of development! Some of the main concept groups are described below but the list is far from exhaustive

“Heaving Buoys” typically harness the differential movement between two parts of a floating structure. This can be transmitted to power generators using mechanical or hydraulic means. Other arrangements propose the use of linear generators.

Oscillating Water Column converters typically use compressed air directly to drive turbines.

Elongated structures may capture energy from a series of waves. They may be flexible structures such as Anaconda’s device or rigid but articulated structures such as Pelamis.

Near-shore technologies may use a buoy or flap to generate hydraulic energy which can be piped to shore and used to power conventional hydroelectric plants.

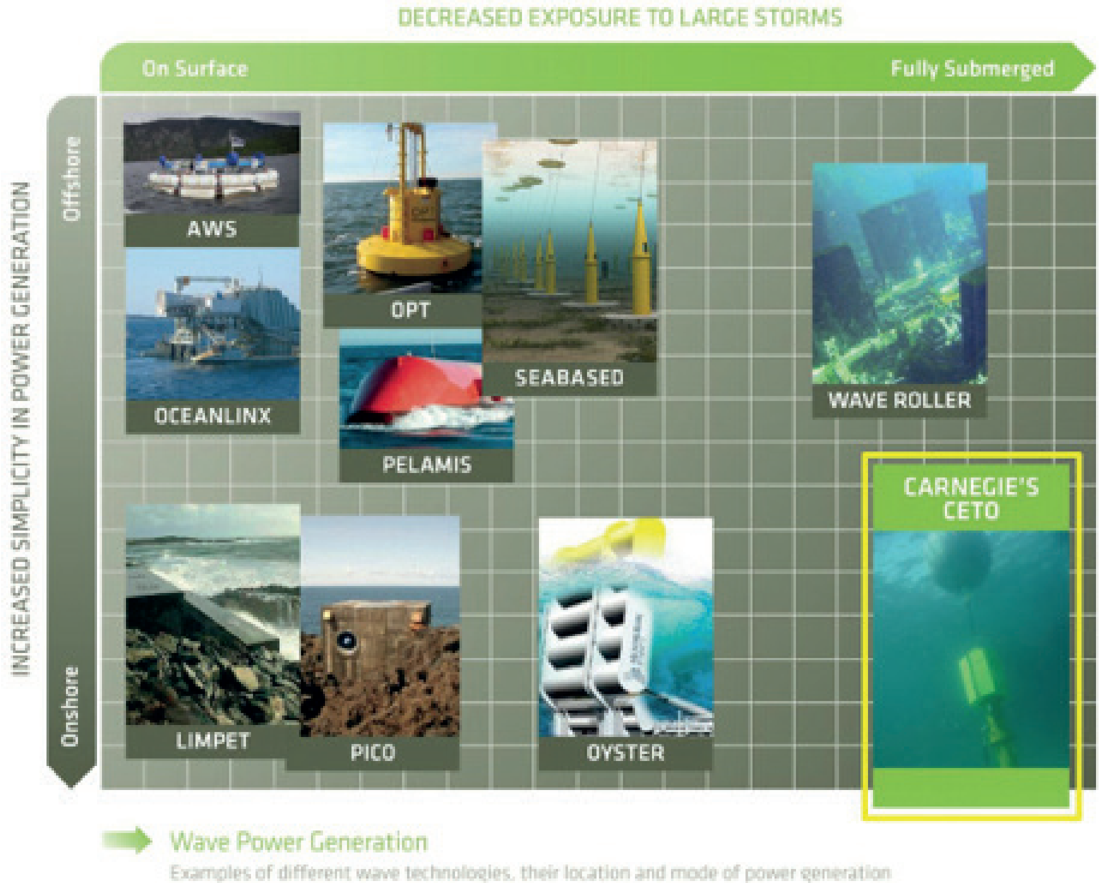
A number of concepts directly mounted on shore or on artificial barrages have also been designed.

Carnegie Wave Energy, an Australian Wave Energy developer, characterises current technologies along two axes:

- Generation onshore or offshore
- Equipment submerged or on the surface

Its technology characterisation looks as follows:

This technology list is by no means exhaustive.



Carnegie Wave Energy Technology Chart

In the top left quadrant are technologies that are on the surface and generate at sea.

One of the most advanced is possibly Pelamis and it is currently undergoing testing at the EMEC site at Orkney.

Two P2 (second generation) machines are undergoing test for the German utility E.ON and the Scottish utility, Scottish Power. E.On plans to use 66 such machines for a 50MW plant off the Scottish coast. At present the P2 machine has a proven average output over 30 minutes of approximately 270kW

Ocean Power Technologies (OPT) has been developing wave energy technology for over a decade. The equipment is a "point absorber" which harnesses the relative movement between two parts of the buoy. Tests of a 150kW (Peak) unit shown below were undertaken in Scotland in 2011.

The company also proposes to deploy its technology off the North America coast. Under development is a 500kW (Peak) device which is planned for installation in a commercial wave farm off the Oregon coast.

Left: tests of a "point absorber", Scotland 2011

Right: tests of Pelamis, Orkney

AWS floating generation technology

AWS is another floating generation technology which has recently been acquired by Alstom (France) and is being developed in Scotland.

The result of this approach is the AWS-III: A multi-cell array of flexible membrane absorbers which convert wave power to pneumatic power through compression of air within each cell. The cells are inter-connected, thus allowing interchange of air between cells in anti-phase. Turbine-generator sets are provided to convert the pneumatic power to electricity.

A typical device will comprise an array of 12 cells, each measuring around 16m wide by 8m deep, arranged around a circular structure with overall diameter of 60m. Such a device is estimated to be capable of producing an average of 2.5MW from a rough sea whilst having a structural steel weight of less than 1300 tonne. The AWS-III will be slack moored in water depths of around 100m using standard mooring spreads.

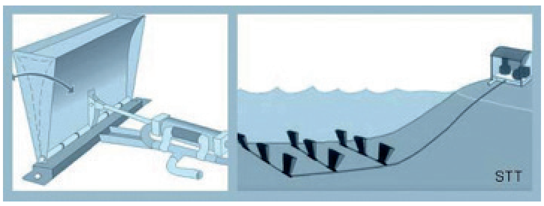
In the top right quadrant of the diagram are technologies that are fully submerged and generate at sea

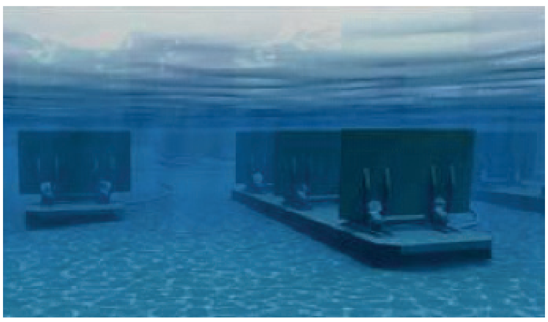
Waveroller is a Finnish technology, owned by the AW Energy Company, which is fully submerged and generates underwater. It consists of a series of flaps which move laterally in response to wave energy pulses. These flaps are in turn coupled to hydraulic cylinders which develop pressure in a hydraulic circuit and in turn are used to power a hydraulic Motor / Generator set.

Top left: Waveroller principle

Bottom left: Waveroller Artists impression

Right: Waveroller deployment September 2012





The current design is based on a 500kW unit. Testing has taken place in late 2012 at a Portuguese site.

On the left bottom of the diagram are examples of on-shore wave technologies, respectively Limpet and Pico.

Voith Hydro's (Wavegen) Limpet unit at the Isle of Islay uses oscillating water column technology and generates using a Wells turbine. The unit was installed in 2000 and has operated for more than 10 years. Further development of the technology has however been limited.

The Pico plant is also an oscillating water column device located onshore in the Azores.

Both the Limpet and Pico plants are early examples of wave energy converters and have demonstrated the operational capability of oscillating water column devices using air turbines.

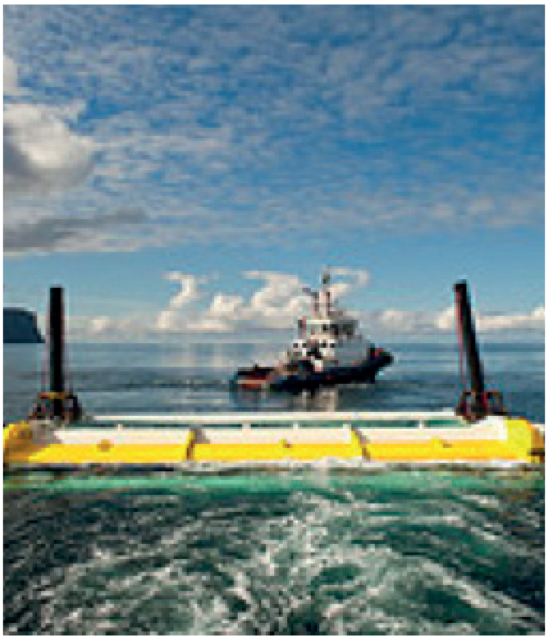
At the bottom right of the diagram are devices which capture hydraulic energy at sea, transmit it to land and generate electricity on-shore.

Aquamarine's Oyster technology is typical of this approach. Although it is not completely submerged while operating it can be folded flat below the surface if desired in certain sea conditions.

One of the main advantages of this approach is to take complex hydraulic-mechanical-electrical energy conversion out of the marine environment and locate it on shore (or potentially on offshore platforms)

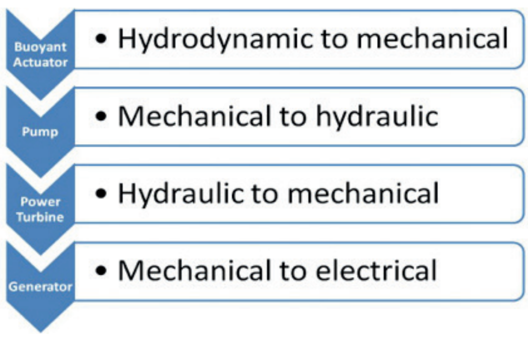
Oyster wave power technology captures energy in near-shore waves and converts it into electricity. Essentially Oyster is a wave-powered pump which pushes high pressure water to drive an onshore hydro-electric turbine. The technology uses a closed circuit with fresh water as a hydraulic fluid and drives a Pelton Turbine on –shore.

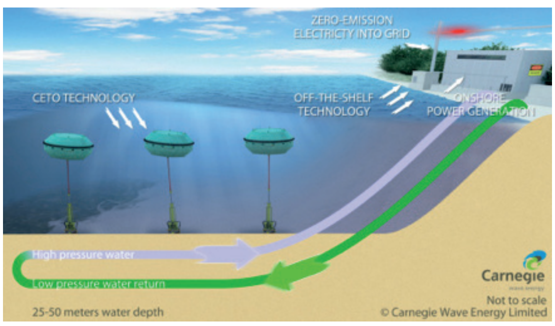
The current unit size at 800kW is being deployed at the EMEC test site in Orkney. The company plans to develop a commercial 40MW plant off the Isle of Lewis.



Left: Aquamarine's 800kW device

Right: Device installation in 2012.






Assembly of the Buoyant Actuator at La Reunion. CETO 4 (Average output estimated at 180kW over 20 minutes)

Carnegie Wave Energy (CWE) has developed a fully submerged technology (called CETO). The technology consists of a number of buoys designed to operate hydraulic cylinders anchored to the sea floor. The hydraulic energy produced is transmitted ashore by pipeline and used to drive a hydraulic motor coupled to a generator. The hydraulic circuit is closed and uses fresh water.

In 2011 the company successfully tested its CETO 3 prototype at a site near Garden Island, south of Perth WA. The unit developed an average output over 20 minutes of 80kW.

CETO technology:

- Sacrifices some energy capture in the interest of survivability by being fully submerged.
- Incorporates design features which limit the capture of energy in high sea states.
- Seeks to utilise proven components from the offshore oil and gas industry
- Focusses on engineered simplicity, particularly in the area of deployment and unit recovery

CWE's CETO 4 generation of technology is undergoing tests currently for EDF at la Reunion. The deployment is being managed by DCNS (France).

The company plans to install a grid connected array of 5 X 240kW CETO 5 units at its Garden island site in 2013.

Summary

Wave energy technology continues to make progress and there is a much improved appreciation of the importance of robust design and careful testing. The more recent development of near shore technologies indicates an investor comfort with the concept of engineered simplicity in offshore equipment. Many companies seek to adapt technologies and learn lessons from the offshore oil and gas industry which has pioneered offshore engineering.

There are perhaps a half dozen competing technology concepts at the forefront of wave energy development at the moment. It is not possible to call the winner and indeed some early stage technology may yet emerge to beat the others.

Investors have been generous to the industry and have suffered several disappointments. It is essential that they see a route to commercialisation emerging over the next two to three years.

The involvement of utilities like E.ON, Scottish Power and EDF as well as OEMs like ABB and EPC companies like DCNS (France) is a very positive sign. These are the companies that will ultimately provide the finance for large scale deployment.

4. Ocean Thermal Energy Conversion (OTEC)

Ocean Thermal Energy Conversion (OTEC) is a marine renewable energy technology that harnesses the solar energy absorbed by the oceans to generate electric power. OTEC uses the temperature differential between cooler deep and warmer shallow or surface ocean waters to run a heat engine and produce useful work. However, the temperature differential is small and this significantly impacts the economic feasibility of ocean thermal energy for electricity generation.

OTEC installations typically use a low boiling point working fluid such as ammonia in a closed cycle arrangement utilising a Rankine cycle. However open cycle arrangements utilising warm surface water as a working fluid are also possible and hybrid arrangements have also been proposed.

Because of the low operating temperature differential, the thermal efficiency of OTEC plants is limited to approximately 7%. Practical efficiencies of 2% - 3% have been demonstrated.

The technology is not new. Operating plants have been demonstrated as long ago as the 1930s. However the plants tend to be very capital intensive, vulnerable to damage in the marine environment and highly uncompetitive in terms of competing power generation technologies.

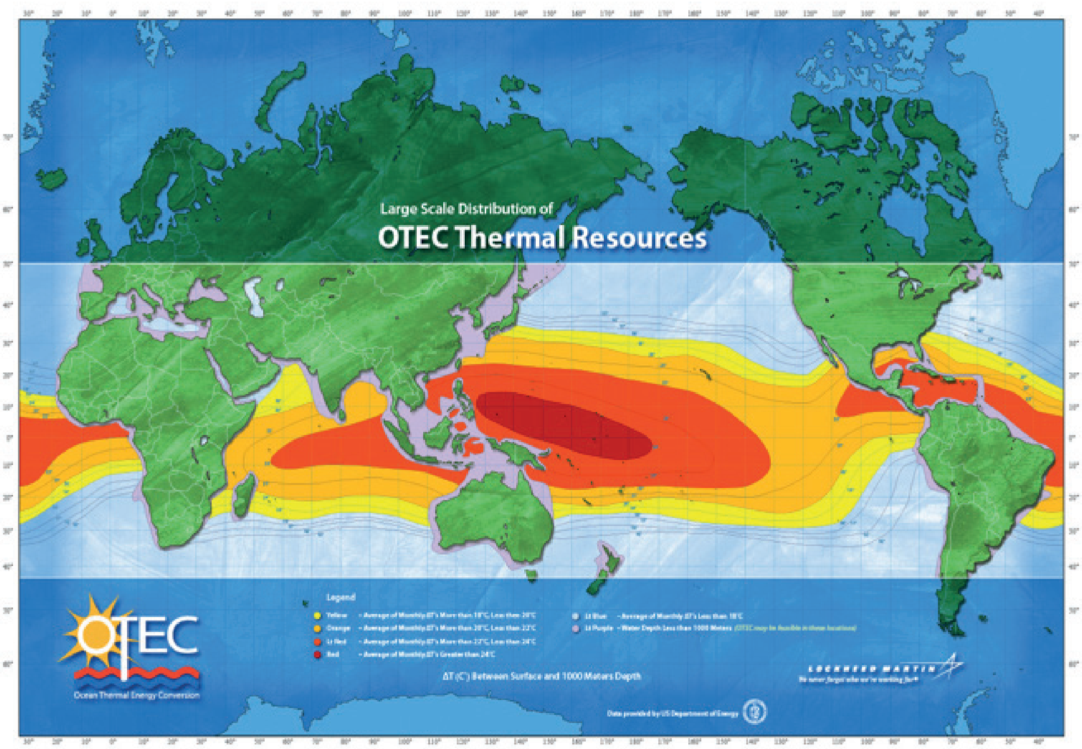
OTEC plants may operate in base load mode which is commercially very attractive and can also be utilised to provide cooling for buildings as well as desalinated water. The production of hydrogen is also feasible permitting the use of ocean thermal energy at locations remote from generating sites.

The largest naturally occurring temperature differentials are located in tropical waters and it is in this area that most experimentation has been focussed, particularly on volcanic Islands like Hawaii where deep cool ocean water is available relatively close to shore (see diagram overleaf).

Three basic plant arrangements have been considered:

- Land based
- Shelf based
- Floating

Land based systems depend on long pipelines from the shore reaching depths of a 1.0km or more in order to access cool ocean water. These pose particular engineering problems in terms of large pipelines crossing the surf zone (see diagram overleaf).



Concepts for floating OTEC plants

Shelf based systems are located beyond the surface zone in relatively shallow water. However they still require pipelines that reach the aforementioned depth.

Floating systems require vertical pipelines reaching down to the cooler waters.

While much engineering effort has been and continues to be expended on OTEC technology, no commercial plants are in existence and the technology continues to strive to be competitive.

Companies and Projects

A number of companies are active in the OTEC area. Some current projects are described below. However this is not an exhaustive overview of current developments.

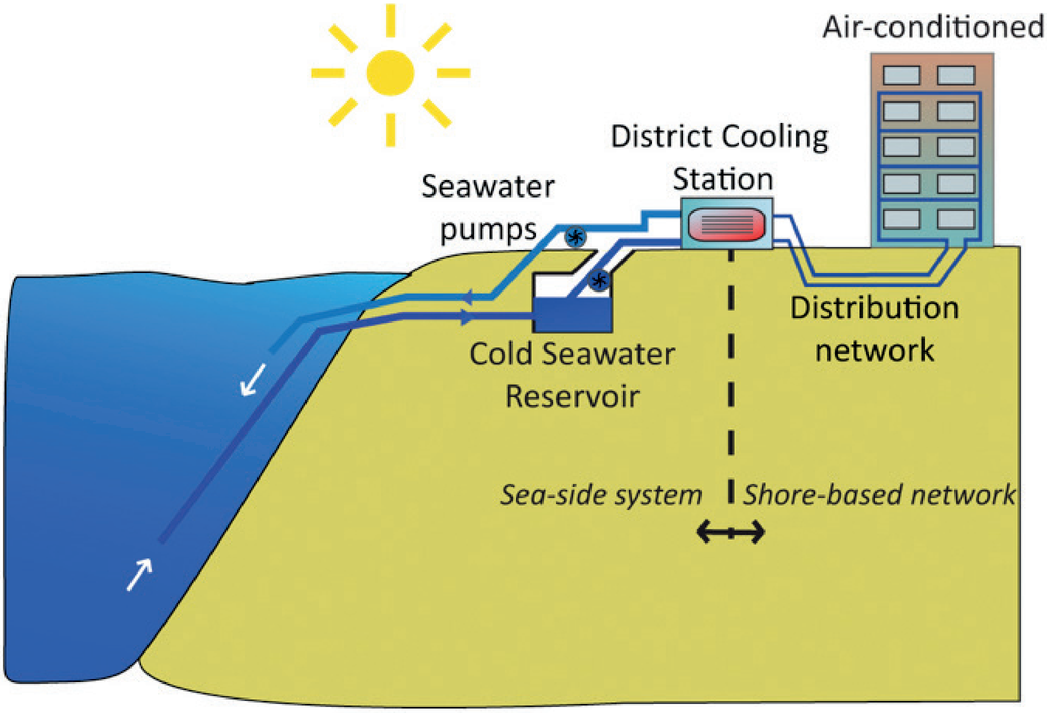
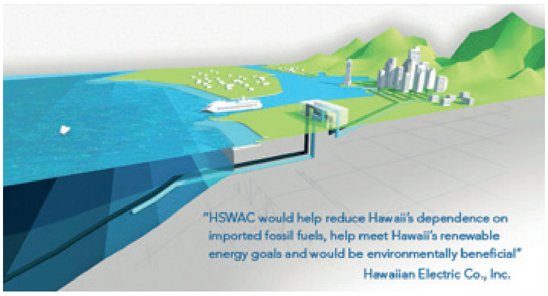
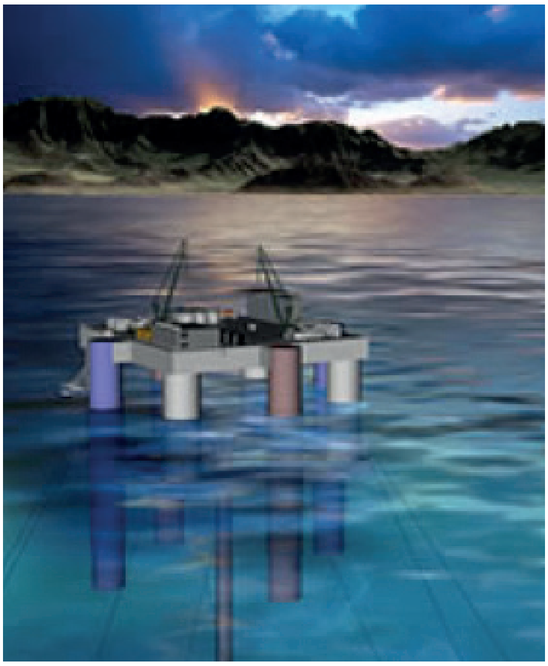


Diagram showing land based system used for cooling





Artistic rendition of a 100MW OTEC plant

For the past few decades the US Government through various agencies, particularly the Department of Defense, has supported the development of OTEC technology, primarily in Hawaii. Lockheed Martin and Makai Ocean Engineering have been engaged in steady development of a commercial scale technology for the past decade.

Lockheed Martin and Makai Ocean Engineering are currently completing the design of a 10MW closed cycle pilot plant. The plant will be designed to be expanded to 100MW. The US Naval Facilities Engineering Command is the main funding source for this project.

Ocean Thermal Energy (OTE) Corporation has signed an MOU with the Bahamas Electricity Corporation to construct two commercial OTEC plants which will produce electricity and water. It also plans a seawater cooling plant to provide cooling to a number of commercial buildings in the Bahamas.

The company reports that it is also in negotiation with an East African Government and the authorities on a Pacific Island for further plants.

Also in Hawaii, The Honolulu Seawater Air Conditioning Company (HSWAC) announced in January 2013 a project to provide cooling to a number of commercial buildings in Oahu. A number of companies are reported to have signed off-take contracts for the $250m project which is scheduled to commence in early 2013.

The district cooling plant will be located on-shore. The cold water pipe will be 1.5m in diameter, will reach a depth of more than 600m and will extend 6.5km from shore.

In Europe DCNS is active in the OTEC development sphere. Much of the development is centred on tropical islands like La Reunion and Tahiti.

DCNS aims to demonstrate the technology's feasibility and its promise for tropical zone communities that are typically highly dependent on fossil fuels. In April 2009, DCNS and the Reunion Island regional council signed an initial R&D agreement to study the feasibility of installing a 1.5-MW OTEC demonstrator on this Indian Ocean Island.

In February 2010, the local government of French Polynesia, the national government, Pacific OTEC and DCNS signed an agreement to conduct a feasibility study of an OTEC plant for Tahiti.

In 2011, the Martinique regional authority in the Caribbean responded to the European Commission's NER 300 call for tenders with a proposal for a 10-MW OTEC pilot plant. As a result, DCNS and the Martinique authority signed a preliminary sizing agreement for a plant that could come on stream as early as 2015.

Summary

While OTEC technology has been demonstrated in the ocean for many years, the engineering and commercial challenges have constrained the development of the technology. In particular the attractiveness of the technology has waxed and waned as the price of oil rose or fell.

Current high oil prices are supporting investor interest in the technology. Proper carbon pricing would further increase its attractiveness.

After a number of years of effort, companies are securing financial support for the first commercial scale projects. The engineering challenges remain however and large scale commercial sized plants have yet to be shown to be competitive with alternative generating technologies.

While oil prices continue to be high, there is a useful niche market for this technology in tropical island locations. It is in such locations that the technology will first be demonstrated at a commercial scale. It remains to be seen if the "cost down" curve is such that the technology will achieve the scale necessary to make it a significant global contribution to electricity production

Annexes

Contents

1. 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, Kyoto1997
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 U.S.	Energy Information Administration / environmental impact assessment
EOR	enhanced oil recovery
EPIA	European Photovoltaic Industry Association
EPR	European pressurised water reactor
ESTIF	European Solar Thermal Industry Federation
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
kWp	kilowatt peak
kWt	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 equivalent606
MW	megawatt
MWe	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	Organization of Arab Petroleum Exporting Countries
OECD	Organisation for Economic Co-operation and Development
OPEC	Organization 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
$U_3 O_8$	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
¾	unknown or zero
~	approximately
<	less than
>	greater than
≥	greater than or equal to

2. 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.

3. Definitions

Coal

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.

Crude Oil

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 Pa.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.

Natural Gas

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 2008 by production (gross less reinjected) 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 2008 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).

Uranium & Nuclear

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; less than US$ 80/kgU; less than US$ 130/kgU and less than US$ 260/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 2009 'Red Book'. Cost categories are expressed in terms of the US dollar as at 1 January 2009. 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 ***insitu*** 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 U3O8 = 0.769 tU.

Reasonably Assured Resources (RAR) 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. RAR have a high assurance of existence.

Inferred Resources (IR) refer to recoverable uranium (in addition to RAR) 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 RAR.

Undiscovered Resources refer to uranium in addition to reasonably assured resources 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 refer 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.

Hydropower

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.

Peat

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.

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Nepal
Netherlands
New Zealand
Niger
Nigeria
Pakistan
Paraguay
Peru
Philippines
Poland
Portugal
Qatar
Romania
Russian Federation
Saudi Arabia
Senegal
Serbia
Slovakia
Slovenia
South Africa
Spain
Sri Lanka
Swaziland
Sweden
Switzerland
Syria (Arab Republic)
Taiwan, China
Tanzania
Thailand
Trinidad & Tobago
Tunisia
Turkey
Ukraine
United Arab Emirates
United Kingdom
United States
Uruguay
Zimbabwe

The World Energy Council (WEC) is the principal impartial network of leaders and practitioners promoting an affordable, stable and environmentally sensitive energy system for the greatest benefit of all. Formed in 1923, WEC is the UN-accredited global energy body, representing the entire energy spectrum, with more than 3000 member organisations located in over 90 countries and drawn from governments, private and state corporations, academia, NGOs and energy related stakeholders. WEC informs global, regional and national energy strategies by hosting high-level events, publishing authoritative studies, and working through its extensive member network to facilitate the world's energy policy dialogue.

Further details at **www.worldenergy.org** and **@WECouncil**

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

For sustainable energy.