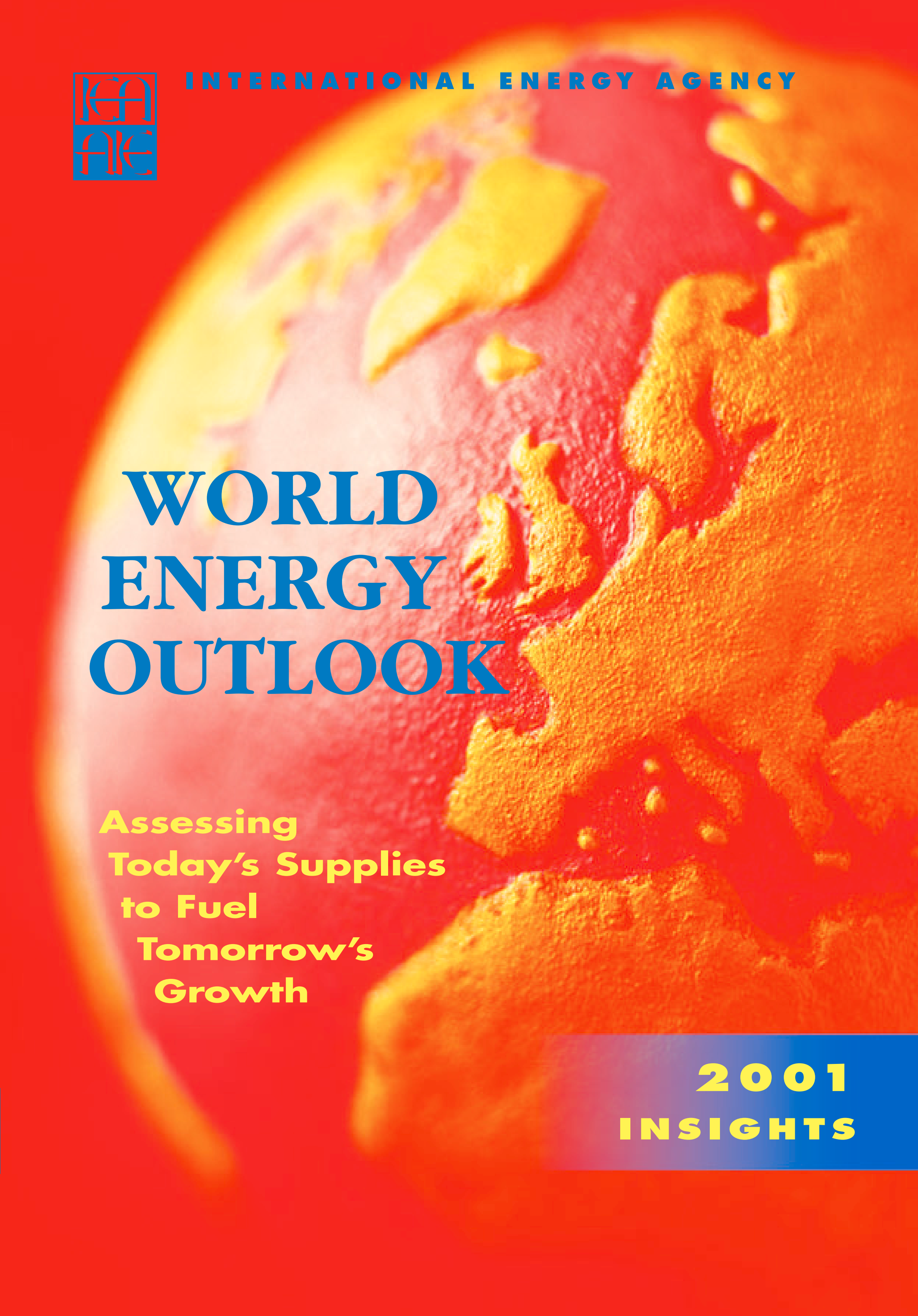

INTERNATIONAL ENERGY AGENCY

WORLD ENERGY OUTLOOK

Assessing Today's Supplies to Fuel Tomorrow's Growth

2001 INSIGHTS

INTERNATIONAL ENERGY AGENCY

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The International Energy Agency (IEA) is an autonomous body which was established in November 1974 within the framework of the Organisation for Economic Co-operation and Development (OECD) to implement an inter- national energy programme.

It carries out a comprehensive programme of energy co-operation among twenty-five* of the OECD's thirty Member countries. The basic aims of the IEA are :

■ To maintain and improve systems for coping with oil supply disruptions;

■ To promote rational energy policies in a global context through co-operative relations with non-member countries, industry and international organisations;

■ To operate a permanent information system on the international oil market;

■ To improve the world's energy supply and demand structure by developing alternative energy sources and increasing the efficiency of energy use;

■ To assist in the integration of environmental and energy policies.

**IEA Member countries : Australia, Austria, Belgium, Canada, the Czech Republic, Denmark, Finland, France, Germany, Greece, Hungary, Ireland, Italy, Japan, Luxembourg, the Netherlands, New Zealand, Norway, Portugal, Spain, Sweden, Switzerland, Turkey, the United Kingdom, the United States. The European Commission also takes part in the work of the IEA.*

ORGANISATION FOR ECONOMIC CO-OPERATION AND DEVELOPMENT

Pursuant to Article 1 of the Convention signed in Paris on 14th December 1960, and which came into force on 30th September 1961, the Organisation for Economic Co-operation and Development (OECD) shall promote policies designed :

■ To achieve the highest sustainable economic growth and employment and a rising standard of living in Member countries, while maintaining financial stability, and thus to contribute to the development of the world economy;

■ To contribute to sound economic expansion in Member as well as non-member countries in the process of economic development; and

■ To contribute to the expansion of world trade on a multilateral, non-discriminatory basis in accordance with international obligations.

The original Member countries of the OECD are Austria, Belgium, Canada, Denmark, France, Germany, Greece, Iceland, Ireland, Italy, Luxembourg, the Netherlands, Norway, Portugal, Spain, Sweden, Switzerland, Turkey, the United Kingdom and the United States. The following countries became Members subsequently through accession at the dates indicated hereafter : Japan (28th April 1964), Finland (28th January 1969), Australia (7th June 1971), New Zealand (29th May 1973), Mexico (18th May 1994), the Czech Republic (21st December 1995), Hungary (7th May 1996), Poland (22nd November 1996), the Republic of Korea (12th December 1996) and Slovakia (28th September 2000). The Commission of the European Communities takes part in the work of the OECD (Article 13 of the OECD Convention).

FOREWORD

Assessing Today's Supplies to Fuel Tomorrow's Growth is the most detailed analysis of energy-supply issues produced by the International Energy Agency since 1995. It identifies and analyses the main forces driving trends in global energy production and supply. These include the cost of developing resources and taking them to market, energy prices and government policies, especially those aimed at countering unwanted climate change. The focus of the analysis is on primary energy.

Our key message is that the world possesses abundant supplies of energy. Proven energy reserves are more than adequate to meet projected demand growth until 2020 and well beyond. But massive investment in energy infrastructure will be needed to exploit these reserves. Mobilising this investment in a timely fashion will require a critical review of existing regulatory and market barriers. The ability to mobilise capital to exploit the low-cost reserves of major Middle East oil producers will decisively affect supply prospects in the next two decades. The cost of supply and the impact of technology, as well as oil prices, will be critical factors in the evolution of natural-gas supplies. There is huge potential for expanding the use of renewable energy, if significant cost reductions can be achieved, backed by strong government support. Beyond 2020, hydrogen-based fuel cells and carbon sequestration hold out the prospect of abundant, clean energy supplies in a carbon constrained world.

The energy-supply trends described in this study have major implications for the governments of producer and consumer countries alike. Growing dependence of IEA Members and other countries on oil and gas imports increases the mutual dependency of exporters and importers, but also heightens the importance for consumers of their readiness to handle any supply disruption. Governments need to address these supply-security concerns. They will also play a key role in creating the regulatory and market framework and in encouraging technology development and deployment. Their environmental policies, including penalties on carbon emissions, will also affect energy supply, mainly through their impact on demand and on the relative value of different fuels.

Many organisations and individuals helped to bring this study to fruition and I thank them for their contributions. I would especially like to acknowledge the help of the Organisation for Petroleum Exporting Countries in providing valuable information on oil supply.

This work is published on my authority as Executive Director of the IEA and does not necessarily reflect the views or policies of IEA Member countries.

Robert Priddle, Executive Director

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World Energy Outlook - 2001 Insights
  Assessing Today's Supplies to Fuel Tomorrow's Growth
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This study required a complex analysis of different fuels. We asked several experts to review early drafts of each chapter. Their comments and suggestions were extremely useful. Responsibility for errors, omissions or misjudgements remains solely with the authors. The reviewers are:

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EXECUTIVE SUMMARY

Fuelling Tomorrow's World

The world has abundant reserves of energy. Proven energy reserves are adequate to meet demand until 2020 and well beyond. Oil will be available throughout the period, although unconventional oil is likely to play a growing role. Proven reserves of natural gas and coal are abundant. There will be no lack of uranium for nuclear power production in the foreseeable future. Renewable energy sources are plentiful and will be more widely used. Beyond 2020, new technologies, such as hydrogen-based fuel cells and carbon sequestration, hold out the prospect of plentiful, clean energy supplies in a carbon-constrained world.

The principal uncertainty in global energy supply prospects is cost. Advances in technology and productivity are driving production and transportation costs lower, but the depletion of the cheapest reserves and the growing distances over which new supplies must be transported are, in many cases, pushing delivered energy costs up. The net effect on supply costs varies among fuels and regions. The cost of supplying natural gas to the main markets is starting to rise with the depletion of near-to-market reserves and the growing need to ship gas from further afield. On the other hand, renewable energy sources, which are usually exploited at a local or regional level, are generally becoming less costly to produce.

The other key factor in the energy-supply picture is the price. Energy prices play a major role in determining the timing and the amount of investment that goes into expanding energy supply capacity. Current supply, in turn, influences price. Because the oil market is partially cartelised, prices are well above the marginal cost of oil supply. Since gas competes with oil products, the oil price, as well as monopolistic elements in many gas markets, keeps the price of gas above its marginal costs too. Future oil prices are very uncertain since they depend heavily on the pricing and production policies of the major producing countries.

Massive Investment in Energy Infrastructure Will Be Needed

Financing for the development of energy-infrastructure is a major challenge. Massive investment in the production, transformation, transportation and distribution of energy will be needed to meet growing demand. The bulk of this investment is needed in developing countries, but the scale of investment will require major capital inflows from industrialised countries.

Mobilising this investment in a timely fashion will require the lowering of regulatory and market barriers. Most major oil and gas producers in Africa, the Middle East and Latin America, recognise the need for foreign involvement. Algeria, Egypt, Libya and Nigeria, among others, have changed their upstream policies and practices to attract joint-venture investment by international oil companies. Since 1992, Venezuela has sought private investment in the oil and gas sectors. Saudi Arabia has recently started to open its upstream gas sector to foreign companies. Key coal producers, including China and India, will need to attract huge amounts of capital to meet their medium-term production targets. Increased foreign direct investment and partnerships between international and national energy companies would make possible more supply projects and would limit investment risk for all participants.

Growing International Trade Must Overcome Security Concerns

Growing international trade in energy, especially fossil fuels, will have major geopolitical implications. Trade is poised to grow rapidly as a result of the regional mismatch between the location of demand and production. Dependence on the Middle East will continue to grow in the net oil-consuming regions, essentially the three OECD regions and some parts of Asia. This situation will increase mutual dependence, but can also be expected to intensify concerns about the world's vulnerability to a price shock induced by a supply disruption. Oil-supply chains will lengthen, and maintaining the security of international sea-lanes will become more important.

Increasing dependence on imports of natural gas in Europe, North America and other regions will heighten those concerns. The recent disruption in liquified natural gas (LNG) supplies from Indonesia has brought home everywhere the risks associated with relying on imports of gas from politically sensitive regions. On the other hand, the expected expansion of international LNG trade could alleviate the supply risks associated with long-distance rigid supply chains if it spurs more short-term LNG trading and more flexible supply.

Governments Will Shape the Energy-Supply Landscape

Global energy supply trends have major implications for the governments of producer and consumer countries alike. Governments will play a key role in addressing supply-security issues, in creating appropriate regulatory and market frameworks and in encouraging technology development and deployment. Environmental policies, including penalties on carbon emissions, will affect energy supply by dampening demand and changing the fuel mix.

The governments of oil- and gas-importing countries are likely to place greater emphasis on improving relations with suppliers; they will also step up measures to deal with short-term supply emergencies or price shocks. The Seventh International Energy Forum, held in Riyadh in November 2000, provided an opportunity for oil producers and consumers to discuss oil market developments. Both sides called for stability, transparency and better data to reduce oil price volatility. Governments and end users are, nonetheless, likely to continue to accept a degree of risk in return for competitively priced oil and gas supplies.

Regulatory and structural reforms in the energy sector will have a major impact on supply prospects. These reforms include the privatisation of state-owned enterprises, the opening up of the energy sector to private capital, the removal of trade and investment barriers and the introduction of competition in gas and electricity through mandatory third-party access to grids. Regulatory reform will increase investment opportunities and encourage the development of new supply projects.

Harmonisation of trade and tariff rules will be especially important to cross-border pipeline projects. Punitive transit fees increase the cost of supply, while geo-political risk can undermine investor confidence and raise the cost of capital. In the transition economies, the implementation of the Energy Charter Treaty could play a key role in improving the trade environment and in encouraging new oil-and-gas pipeline projects from the Caspian Sea area.

Research and development will be vital to reducing energy-supply costs. Governments can influence the pace of supply cost reduction by encouraging research and development expenditures. Both public— and private-sector R&D expenditures have declined in the past decade. Increasing spending on R&D could have a major positive effect on energy-supply technology and security.

Conventional Oil Reserves Can Comfortably Meet Demand to 2020, but Considerable Investment is Needed

Proven oil reserves are sufficient to satisfy projected demand for the next two decades. By 2020, oil production is projected in our *World Energy Outlook 2000* to reach 115 million barrels per day, or 40% of the world's total energy supply. Oil will retain its position as the single largest source of primary energy. Over the next two decades, most of the expected demand growth will come from the transport sector, where the potential for replacing oil with another fuel is very limited. International trade is expected to double due to the increasing concentration of production capacity in a small number of countries with large, low-cost reserves.

Further reductions are expected in the cost of producing unconventional oil, such as synthetic crude from oil sands and gas-to-liquids conversion. Unconventional oil may well exceed current projections and account for a much greater share of total oil resources and supply by 2020. Enormous volumes of unconventional oil lie in oil sands in Canada and in heavy and extra-heavy oil deposits in Venezuela.

Global oil production need not peak in the next two decades if necessary investments are made. Declining production in ageing oil reservoirs means that much new capacity will be needed to offset expected production declines and to meet demand growth. Future oil prices and trends in production costs will be critical factors in attracting timely investment in new oil-production capacity.

But the pattern of decline needs to be better understood. Advances in technology allow production from new reservoirs to peak higher and earlier, thereby improving investment returns. But this leads to faster rates of decline. The overall rate of decline will also be strongly influenced by declining production from ageing giant oil reservoirs. Both these effects need close scrutiny.

Major Middle East oil producers have an opportunity and challenge to exploit their low-cost resources, but their ability to mobilise capital is uncertain. Their production and investment plans will be closely linked to their pricing policies. They will need to establish a framework that is attractive to foreign investors, where domestic sources of capital are inadequate.

Producers, somewhat paradoxically, do better when prices are moderate rather than when they are very high or very low. The impact of oil prices on supply and demand was analysed using high- and low-price scenarios in the *World Energy Model.* The results of these scenarios were compared with the *WEO 2000* Reference Scenario. The analysis suggests that neither very high nor very low oil prices would improve cumulative revenues for the major producers over what they can earn under the moderate-price conditions envisaged in the Reference Scenario.

The development and deployment of new technology will be crucial to reducing supply costs and improving productivity. In recent years, technology has improved the efficiency of finding, developing and producing oil. New technology, including underground sensors and controls, will reduce production cost and improve ultimate oil and gas recovery.

Government policy and industry restructuring will also influence upstream investment. Increased productivity and improvements in market conditions could lead to major increases in production from several countries *outside* OPEC. Russia has the largest growth potential, particularly given the strong performance in recent years.

Natural Gas Markets Are Poised for Rapid Growth, but the Cost of Transporting Gas Could Rise

Natural-gas resources are abundant and can easily meet the expected surge in demand in the next two decades. Proven gas reserves have doubled over the past twenty years, and the ratio of global reserves to annual production now stands at 60:1. Estimated remaining resources, including undiscovered gas, represent from 170 to 200 years of supply. Most of today's gas reserves were discovered in the course of exploration for oil. But exploration specifically for gas accounts for a growing proportion of overall exploration spending by international oil companies. There is also a trend toward deepwater exploration and development.

Exploiting the world's gas resources will require massive investment in production facilities and infrastructure to transport gas to market. The share of transportation in total supply costs will rise, as supply chains lengthen with the depletion of reserves located closest to markets. Pipelines will remain the principal means of transport for gas, but liquefied natural gas is likely to play a growing role. LNG trade is set to expand dramatically in the Asia/Pacific and Atlantic Basin regions.

Gas prices to producers, both in absolute terms and relative to oil prices and gas supply costs, will be the key driver of investment in gas projects. Higher wellhead prices than in the 1990s will probably be needed to elicit the necessary investment in supply infrastructure, as costs rise. Nonetheless, there is scope for prices to fall from the peaks reached in late 2000 and early 2001.

Technology will be crucial in moderating supply costs. Advanced technology, improved management practices and project design and gains in productivity have sharply reduced gas costs. Advances in technology will be needed to reduce supply costs further and open up new supply sources. Costs may drop more slowly in the coming decade than in the last, especially if research budgets continue to decline. On the other hand, innovative technology could open up opportunities for exploiting resources that current technologies cannot tap. Continued advances in gas-to-liquids technology could allow the development of some reserves currently considered to be "stranded" due to their small size and remoteness from markets.

The impact of competition on investment in gas-supply projects is highly uncertain. The spread of competition will stimulate the development of spot markets and hasten the de-coupling of gas from oil prices in long-term contracts. Although long-term contracts will become shorter, they will still be used. To the extent that competition lowers prices at the wellhead and at borders, it can discourage some potential upstream developments. At the same time, however, competitive markets provide new opportunities for producers to market their gas. By reducing transportation costs, competition may also allow for higher netbacks at the wellhead.

Market growth and new supply chains will promote market integration. Rising demand and expanding transportation networks will intensify market integration at the regional and global level. Physical connections between the main regional markets will expand, with the prospect of rapid expansion in LNG trade. Changes in the way new LNG projects are structured, including tying less capacity to specific supply chains, could lead to greater commercial opportunities for LNG projects.

Coal-Supply Prospects Hinge on the Environmental Acceptability of Coal Use

World reserves of coal are enormous and well dispersed geographically compared with oil and natural gas. Economically recoverable proven coal reserves are close to one trillion tonnes, representing about 200 years of production at current rates. Almost half the world's reserves are located in OECD countries. The size and distribution of these reserves virtually obviates supply-security concerns about coal. The quality of coal deposits determines the cost of, and the prospects for, production, rather than the actual size of a country's reserves.

The most uncertain factor affecting future coal supply is the impact of environmental policies on demand, especially in power generation. Demand will depend largely on whether clean-coal technologies in the power sector can meet environmental concerns while simultaneously producing electricity that is competitive with that produced using other fuels. Concerns about future environmental regulations, including carbon-emission constraints, could deter investment in new mining projects.

Technology is expected to drive continuing improvements in efficiency and reductions in the cost of coal extraction and preparation. Health and safety concerns will encourage further automation which will reduce labour costs. Technology will help to lower the costs of meeting increasingly stringent environmental regulations. Continued growth in the size of mines is also expected to improve productivity.

Subsidies to the coal industry will remain an important feature in some countries. A number of hard-coal producing countries in the OECD still subsidise indigenous producers, to support local economies that were originally built around coal. The amount of subsidised production has declined significantly over the past decade, but the complete elimination of subsidies is unlikely in the foreseeable future. Subsidies are common in countries outside the OECD, although many of these countries are also reforming and restructuring their coal industry in order to improve performance and investment prospects.

Further Cost Reductions Are Needed to Boost the Role of Renewables

Production of primary energy from renewable sources is expected to grow rapidly over the next two decades. Nonetheless, their share in the global energy mix will probably remain small in the absence of determined government interventions. In the OECD, most of the growth is expected to come from wind and bioenergy, supported by policies and measures to curb climate-destabilising greenhouse-gas emissions and to diversify the energy mix. Hydropower is expected to be the fastest-growing renewable energy supply source in developing countries, based on further development of economically exploitable resources.

Renewable energy has the technical potential to meet large portions of the world's energy demand, but under current market conditions, the economic potential of renewables is much lower. Over the next twenty years, the economics of renewables are expected to improve as a result of technological improvements and the economies of scale resulting from expanding markets. Market valuations of carbon emissions can also favour renewables.

The most important benefits from using renewable energy sources are environmental protection and greater security of supply. Renewable energy plays a key role in strategies to fight global warming. Their use will be boosted if a market value for carbon emissions is introduced. Renewable energy can often enhance security of supply, since most renewable energy sources are indigenous.

Developing renewable energy resources will require sustained investment in infrastructure. In the OECD, investment in renewables to achieve a 4% share in electricity generation in 2020 is expected to be $90 billion. This is equivalent to 10% of the total power sector investment over the next twenty years. If very strong efforts are made by governments to promote and subsidise renewables, their share could rise to 9% in 2020. The necessary investment requirements would be about $230 billion.

The costs of renewable-energy technologies have already fallen but further reductions are needed for them to compete with fossil fuels. The rate at which costs will decline in the future is uncertain. If fossil-fuel prices do not increase sharply and if governments do not introduce radical new policies, few renewable energy sources will be able to compete with fossil fuels in the near term. Renewable energy can, however, be cost-effective in specific applications. Some technologies, such as wind, are close to being competitive, while others need to see dramatic cost reductions. Competing land uses and constraints on dispatchability may limit supply.

Uranium Resources for Nuclear-Power Production Are Ample

The needs of nuclear-power generation are currently met by primary production of uranium and by stockpiles and inventories. While supply from stockpiles has increased, uranium production has declined over the past few years. Known reserves and uranium from secondary sources guarantee a secure supply for the next twenty years.

Uranium production is likely to rise in the medium term. Low prices over the last few years have meant that only low-cost uranium deposits have been mined. Uranium production in the near term will come from the most efficient producers, Canada and Australia. There remains considerable uncertainty about future production in the countries of the former Soviet Union, which have ample resources, but face problems in securing funding.

There is considerable uncertainty about secondary supplies. Much of this uncertainty is due to the amount of defence-related uranium that may eventually reach the commercial market. Low-enriched uranium blended from highly-enriched uranium from Russian warheads will help supply the market over the next several years.

Uranium prices will remain modest in the medium term, but they may rise over the longer term as secondary supplies are depleted. As secondary supplies are drawn down, prices will probably rise to better reflect production costs. Because of the long lead time between the discovery and production of uranium, ten to fifteen years in most cases, producers must be assured that prices will remain high enough to cover exploration and development expenses.

The Energy Supply Outlook Beyond 2020 Will Depend on Technology

Production costs will be more important to the long-term energy-supply outlook than the resource-base. Resources will not limit natural gas and coal production until well beyond 2020, although costs may increase as the lowest-cost reserves are depleted. Production of conventional oil is expected to peak first. But technology could delay the peak of production and unconventional oil could fill any supply shortfall, albeit probably at higher cost. The coal-supply outlook depends largely on whether ways can be found to use coal in an environmentally acceptable way.

The extent to which governments encourage technologies that generate low- or zero-carbon emissions and the costs involved are key issues in the long term. Fossil-fuel resources are more than adequate to meet energy demand well beyond 2020, but continued reliance on them may require the large-scale introduction of technologies to capture carbon. How much this will cost is very uncertain.

Beyond 2020, the role of renewable energy in global energy supply is likely to become much more important. The increasing need for new power-generation capacity will create real opportunities for renewable energy to penetrate the power sector. How rapidly it does so will depend on its cost relative to that of competing technologies, taking account of any carbon taxes or penalties that may be imposed. Technological innovation will be needed to get costs down.

The future of nuclear power is uncertain. Some governments may seek to expand or introduce its use as a way of reducing carbon emissions or enhancing fuel diversification. But there will be countervailing pressures to abandon nuclear energy altogether unless concerns over environmental impact and safety are met. Most of today's nuclear plants will reach the end of their life some time beyond 2020. Decisions about their replacement will need to be taken well in advance.

A number of technologies under consideration or active development could radically alter the long-term supply picture. The main focus of current research on new supply technologies is on hydrogen production and use. Hydrogen technology holds out the prospect of large-scale energy supply with minimal environmental impact. The amount of carbon and other emissions from hydrogen-based energy will depend on how the hydrogen is produced. Fossil fuels may provide the initial source of energy for producing hydrogen for use in fuel cells. Much later, depending on how technology advances, hydrogen production may be based on electrolysis of water using nuclear or renewable energy. In that case, net carbon emissions could be negligible. Carbon sequestration — the separation of CO_2 from fuels and its storage in oceans or geological formations — could also have a profound impact on the long-term prospects for energy supply, if technologies are competitive.

Governments will play an important role in encouraging technological progress. Technology development and deployment are strongly influenced by government actions, including pricing and taxation policies and direct funding of research. All governments have expressed their commitment to step up efforts to reduce CO_2 emissions. Government policies aimed at reducing the risk of a supply disruption or promoting more efficient markets will also affect the long-term supply outlook.

CHAPTER 1
BACKGROUND TO THE STUDY

Objectives and Scope of the Study

Study Objectives

The primary objective of this study is to identify and analyse the factors that will determine global energy production and supply in the medium to long term. This study extends and updates the analysis of supply in the 2000 edition of the *World Energy Outlook (WEO)*. It also updates a study of the supply outlook for oil, gas and coal carried out in 1995.[1] Box 1.1 summarises major developments in energy supply since the quantitative analysis of *WEO 2000* was completed in mid-2000.

Box 1.1: **Recent Major Developments in Energy Supply**

Oil price volatility and uncertainty about future economic conditions were the primary drivers of global energy markets in 2000 and 2001. Tightness of oil and gas supplies, moves by OPEC to keep oil prices high and regional power shortages in North America and elsewhere have brought energy security back to the top of the economic policy agenda. Uncertainty about the future of the Kyoto Protocol without US support also has implications for the primary energy mix. Key developments include the following:

- Surplus oil-production capacity has continued to shrink in line with rising demand and stagnant installed capacity, putting upward pressure on prices and exacerbating price volatility. Unutilised oil production capacity in OPEC countries is estimated to have fallen to only 2 mb/d in 2000, or about 6% of total OPEC capacity.
- Atlantic Basin crude-oil prices peaked at over $30 per barrel in late 2000 and fell back to around $25 per barrel by mid-2001.

1. IEA (1995).

Gas prices were similarly volatile, because of contractual price linkages and inter-fuel competition.

- Interest in LNG projects has surged with higher gas prices. Projects under development or planned would double existing capacity of 120 million tonnes per year by about 2010 if they all proceed.
- World coal consumption increased in 2000 (by close to 1%) for the first time since 1996, as a result of higher power-station use.
- Renewed interest in building new nuclear stations has emerged in some IEA countries, including the United States, spurred by high power prices and projected capacity shortfalls. Germany is pressing ahead with plans to close its reactors.
- The European Union adopted in July 2001 a directive that aims to increase the proportion of the EU's electricity production that comes from renewable energy sources from around 14% at present to 22% by 2010.
- Natural gas remained the fuel of choice for most new power stations. In 2000, about two-thirds of all new stations ordered were natural gas-fired. Coal and heavy fuel oil accounted for a little over 10%; hydropower, 7%; diesel, 7%; wind and other non-hydro renewables, 5%; and nuclear, 2%.
- The new US Administration issued an energy strategy, including measures to boost indigenous energy production and to encourage more efficient energy use.

The economics, and specifically the cost, of energy supply provide the backbone of the analysis. It covers the effects of such factors as resources, technology and government policies. The focus is on primary energy. Transformation activities such as power generation and oil refining are not considered explicitly. Supply prospects are also analysed at the regional and country level for most fuels.

Scope of Analysis

In the *WEO 2000* Reference Scenario, incremental energy supply requirements were projected to be around 30% higher over the next two decades than in the previous two decades. As with any attempt to project future energy developments, however, uncertainties surround the *WEO*

2000 projections. The exogenous assumptions concerning economic and population growth and prices are the main sources of uncertainty. The supply projections are sensitive to factors that directly affect the amount and cost of supply as well as to factors that influence demand. A factor that reduces demand would lead to lower supply and, other things being equal, a lower marginal supply cost. *WEO 2000* gave particular attention to demand-side factors. By contrast, this study focuses on supply-side factors.

The cost of developing resources and transporting them to market and the pricing policies of energy producers are central to the medium-term outlook for energy supply. One of the main conclusions of *WEO 2000* was that, over the period to 2020, resources would not be a limiting factor to supply at the global level. Some increase in energy prices, however, may be necessary to stimulate the increase in supply to meet projected demand. In the case of oil, higher prices may occur due to declining share of non-OPEC production and, consequently, increasing reliance on a small number of Middle East producers. The market power of these producers will, therefore, increase. In the case of gas, prices may increase due to rising oil prices as well as to higher marginal supply costs, as consuming regions seek out more distant supplies. These oil and gas market trends have major implications for the energy-supply security of IEA Members and other import-dependent countries. Coal prices are assumed to remain flat over the entire projection period.

Thus, it is the cost of production and transportation rather than resource availability that is the key to the global supply outlook. Resources are nonetheless important to supply prospects at the regional and national level. The *WEO 2000* oil- and gas-supply projections were based predominantly on resource assessments by the United States Geological Service (USGS). The study here reviews the USGS and other estimates of resources and reserves. It also analyses quantitatively the impact of price on reserves. The prospects for coal supply are assessed in terms of production and transportation costs. The study assesses the economic potential of the various renewable-energy technologies that may play a role in meeting energy needs to 2020.

This study also analyses in a quantitative fashion other factors that can influence trends in energy costs and supply. These include government policies and measures such as taxes, subsidies and regulations in support of environmental or other goals. Market developments, such as the emergence of competition in the network-energy sectors and changes in contractual relationships between different players in the supply chain, can also affect supply.

Technological advances and technology breakthroughs could radically alter the long-term picture for energy supply beyond 2020. The earth contains enormous resources of non-conventional fossil fuels, such as gas hydrates and coalbed methane. Renewable energy sources such as biomass, solar and wind power and ocean energy could also make a large contribution. Hydrogen technologies based on fossil fuels or renewable sources could ultimately meet most of the world's energy needs. These resources hold out the prospect of abundant supplies for many decades if the technology is developed to exploit them economically.

This study addresses these issues in an objective way. It does not promote the production or use of any particular fuel nor does it recommend government policies. We hope that our analysis will provide an objective basis on which policy-makers can develop appropriate policies and measures in pursuit of their own national or regional policy goals.

Major Findings of *WEO 2000*

Overview

The 2000 edition of the *World Energy Outlook* provides the IEA's latest world energy projections to 2020.[2] The central projections are derived from a Reference Scenario that takes account of a range of major new policies and measures adopted in OECD countries — many related to commitments under the Kyoto Protocol — enacted or announced up to mid-2000. The Reference Scenario does *not* include possible, potential or even likely future policy initiatives.

The following major trends characterise the Reference Scenario projections:

- World energy use and related CO_2 emissions will continue to increase steadily.
- Fossil fuels will account for 90% of the world's primary energy mix by 2020 — up slightly on today.
- The shares of different regions in world energy demand will shift significantly, with the OECD share declining in favour of developing countries.

2. See IEA (2000) for the assumptions and methodology that underpin the projections summarised here.

- A sharp increase will occur in international trade in energy, especially oil and gas.
- The reliance on imported oil and gas of the main consuming regions, including the OECD and dynamic Asian economies, will increase substantially, particularly in the second half of the projection period.
- Despite government policies and measures in OECD countries, energy-related CO_2 emissions in 2010 will still be much higher than required to meet commitments under the Kyoto Protocol.

Energy Demand

Projected *world primary energy demand* increases by 57% between 1997 and 2020, or at an average annual rate of 2%.[3] This compares with an annual average growth rate of 2.2% from 1971 to 1997. World energy intensity — primary energy demand per unit of real GDP — is expected to decline over the projection period by 1.1% a year, equal to the historical rate since 1971.

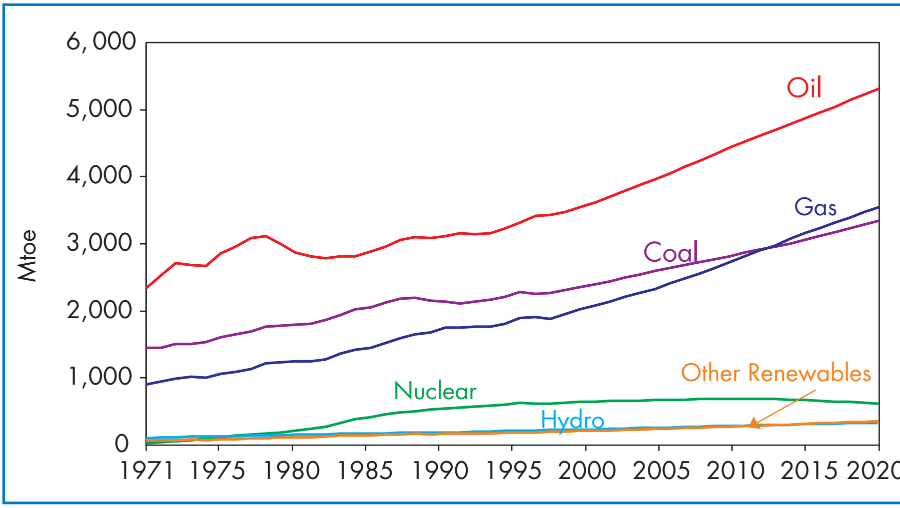
Oil remains the dominant fuel in the primary energy mix with a share of 40% in 2020, after 1.9% annual growth over the projection period. This is almost identical to its share today. The volume of world oil demand is projected at close to 115 million barrels per day in 2020, compared with 75 mb/d in 1997.

Natural gas is the second fastest growing energy source after non-hydro renewables. Gas demand rises at 2.7% per annum over the projection period, and its share in world primary energy demand increases from 22% today to 26% in 2020. New power plants, using high-efficiency combined-cycle gas turbine (CCGT) technology, will provide the bulk of incremental gas demand.

Projected world *coal* demand advances by 1.7% a year, slower than total primary energy demand, so that its share declines slightly, from 26% in 1997 to 24% in 2020. In the OECD, virtually all the increase in demand for coal stems from power generation. China and India contribute more than two-thirds to the increase in world coal demand over the projection period.

3. The *WEO 2000* projections do not include use of combustible renewables and waste (CRW) in developing countries, because it is mainly non-commercial and, therefore, hard to measure. However, CRW, which is mainly biomass, is discussed in Chapter 5.

Figure 1.1: **World Primary Energy Demand by Fuel**

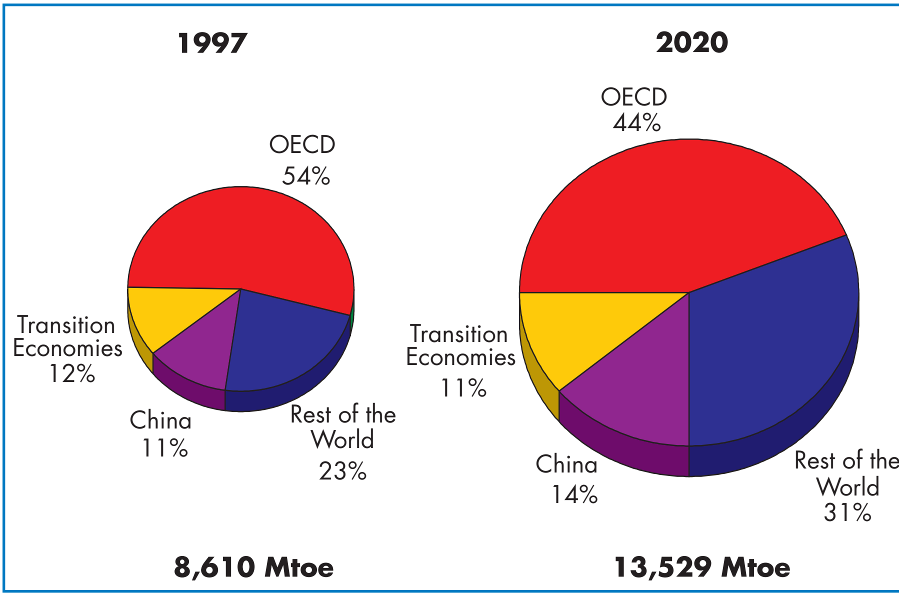


Source: IEA (2000).

Electricity demand grows more rapidly than for any other end-use fuel, at an average annual rate of 2.7%. Its projected share in world final energy consumption increases from 17% today to 20% by 2020. The increase is strongest in non-OECD regions where the share of electricity in final energy demand reaches 19% in 2020, equivalent to that of the OECD today.

The bulk of the projected increase in world energy demand will come from developing regions. They account for 68% of the increase between 1997 and 2020. OECD countries contribute only 23%. As a result, the OECD's 54% share in world primary energy demand declines to 44% by 2020, while that of developing countries rises from 34% to 45%. The share of the transition economies (Central and Eastern Europe and the former Soviet Union) declines slightly. Rapid economic growth and industrial expansion, high rates of population increase and urbanisation and the substitution of commercial for non-commercial fuels drive demand growth in developing countries. Low energy prices in many developing countries also play a part, although this factor will become less important as governments phase out subsidies.

Figure 1.2: **World Primary Energy Supply by Region**



Source: IEA (2000).

Table 1.1: **Inter-Regional Energy Trade*** (Mtoe)

	1999	2010	2020
Oil	1,348	2,157	2,886
Natural gas	213	336	565
Coal	110	127	148
Total	1,671	2,620	3,599

* Does not include international trade within regions, which can be very large.
Source: IEA analysis.

Energy Production and Trade

The *WEO 2000* views the physical world oil-resource base as adequate to meet demand over the projection period. Although oil industries in some countries and regions are maturing, the resource base of the world as a whole is not a constraining factor. No global "supply crunch" is expected before 2020. To bring resources to market, however, will demand large and sustained capital investment, particularly in Middle East OPEC countries. This is reflected in the assumption that the international crude oil price remains flat at $21 per barrel in today's money until 2010, but then rises steadily to $28 through to 2020. The concentration of oil resources in a small number of producing countries will also mean an increase in the oil-import dependence of the major consuming regions. Regional trends in production of each fuel are discussed in Chapters 2 to 6.

A big increase in the *international trade* in fossil fuels is projected to meet the widening gap between consumption and indigenous output in many parts of the world. Regions that depend on imports to meet a major part of their oil needs — notably the three OECD regions and non-OECD Asia — will become even more dependent on imports over the projection period. The OPEC countries are expected to supply much of this increase in import requirements. International trade in natural gas also grows in all regions. Europe becomes increasingly dependent on imports of gas, while net imports into North America also grow steadily. Big increases in gas imports are also expected in the Asia/Pacific region. Coal trade also increases, mainly to Asia/Pacific markets.

CHAPTER 2
GLOBAL OIL SUPPLY OUTLOOK

Summary

There is enough oil to comfortably meet demand to 2020 from remaining reserves

- Sufficient proven oil reserves exist to satisfy projected demand during the next two decades. Oil will retain its position as the single largest source of primary energy. In 2020, oil production of 115 million barrels per day (mb/d) will represent 40% of the world's energy mix.
- Global proven reserves of oil, not including unconventional oil, are estimated at about one trillion barrels. Consumption of oil in 2000 was about 28 billion barrels. Some 730 billion barrels will be needed to satisfy cumulative oil demand for the years 2000 to 2020. The volume of oil that can ultimately be recovered will increase during the projection period due to expected reserves growth and discovery of additional oil.
- The volume of recoverable oil resources is uncertain due to difficulties in accurately locating and measuring oil underground. The assessments of economically recoverable reserves fluctuate with the changing expectation of the future oil price and supply cost. They are also influenced by the pace of technological development and deployment.
- Technological developments that lead to better measurements affect both the volume of oil that can be confidently thought to exist, as well as the amount that can be economically recovered from known reservoirs. The most recent US Geological Survey resource assessment includes a new category for the growth in reserves that can be expected over time. It also updates the estimates of remaining reserves and of oil resources that remain to be found.
- There will be further reductions in the costs of unconventional oil supplies such as synthetic crude from oil sands and gas-to-liquids conversion. Unconventional oil may exceed projections and

account for a growing share of total oil resources and supply in the period to 2020. Enormous volumes of unconventional oil exist in oil sands in Canada and in extra-heavy oil deposits in the Orinoco belt of Venezuela.

But the investment required to increase supply is considerable and will depend critically on cost and price

- Global oil production need not peak in the next two decades if necessary investments are made. Declining production in ageing oil reservoirs, means that much new capacity will be needed to offset expected production declines and to meet demand growth. Future oil prices and trends in production costs will be critical factors in attracting timely investment in new oil-production capacity.
- The impact of the natural decline in production from existing developed reserves needs to be better understood. Advances in technology allow production from new reservoirs to peak higher and earlier, thereby improving investment returns. But this leads to faster rates of decline. The overall rate of decline will also be strongly influenced by declining production from ageing giant oil reservoirs. Both these effects, if not addressed, could dampen the supply prospects.
- A decision to invest capital today will determine production capacity several years in the future. Investment in developing oil reserves will be undertaken if there is confidence that an adequate return on capital can be generated. This confidence is reduced by uncertainty about development and production costs, future oil prices and demand. Oil-price volatility contributes to uncertainty and chokes off investment. Investment risk can also rise with changes in the political and social environment.
- Producers, somewhat paradoxically, do better when prices are moderate rather than when they are very high or very low. The impact of oil prices on supply and demand is analysed using high- and low-price scenarios in the *World Energy Model.* The results of these scenarios are compared with the *WEO 2000* Reference Scenario. The analysis suggests that neither very high nor very low oil prices would improve cumulative revenues for the major producers over what they can earn under the moderate-price conditions envisaged in the Reference Scenario.
- More than half of the world's remaining conventional oil reserves is concentrated in the Middle East, which currently provides 26% of

global oil production. Russia holds a further 14% of reserves, and accounts for less than 9% of production. However, the pace of oil-supply growth from the Middle East, as well as from Russia, will depend upon investment choices considering all the world's exploitable oil resources. Major Middle East oil producers have an opportunity and challenge to exploit their low–cost resources, but their ability to mobilise capital is uncertain. A framework that is attractive to foreign investors will be needed, especially where domestic sources of capital are inadequate.

The development and deployment of new technology will be crucial to reducing supply costs and improving productivity

- In recent years, technology has improved the efficiency of finding, developing and producing oil. New technology, including underground sensors and controls, will reduce production cost and improve ultimate oil and gas recovery. The greater use of information networks could also reduce uncertainty about real-time supply availability and sustainable production capacity.
- Continuing advances in upstream technology could extend the duration of oil production in mature areas and older fields through cost-effective, reliable production-rate enhancement. They could also increase the total volume of oil recovered from the reservoir.
- The Middle East has the world's lowest oil supply costs. However, supply costs in Russia have fallen considerably in recent years, as have the costs of deepwater oil production. The projections of major international oil companies indicate that supply costs are expected to fall in the short term with further improvements in efficiency and productivity.

Upstream investment will also be influenced by government policy and industry restructuring

- Taxation, economic and environmental policies and government initiatives to enhance supply security in oil-importing countries will affect the development of the upstream oil industry. The overall investment climate in producing countries will have an impact on the industry's willingness to invest in developing production capacity. This will be particularly important in the Middle East. Considerable amounts of capital are required. The cost of this capital could be reduced and the investment returns improved by liberalisation of the investment and trade regimes in the host countries.

- Increasing efficiency and transparency, achieved through mergers, privatisation and competition, have reduced the cost of oil production and enhanced the reliability of oil supply. A continuation of these trends is expected to lead to further improvements in oil-industry productivity and predictability.
- This study indicates that reductions in the supply cost and improvements in market conditions could lead to substantial increases in production from several countries *outside* OPEC. Russia has the largest growth potential, with output likely to exceed earlier projections, particularly given the strong performance in recent years.
- Net inter-regional trade in oil will more than double between now and 2020 due to the increasing concentration of oil supply in a limited number of countries, and the growing import requirements of many consumer countries. Over the next two decades, most of the expected growth in oil demand will come from the transport sector, where the potential for replacing oil with any other fuel is limited. Increasing dependence on the Middle East will inevitably lead to increased concerns about the security of supply.

Unconventional oil resources could play an increasingly important role

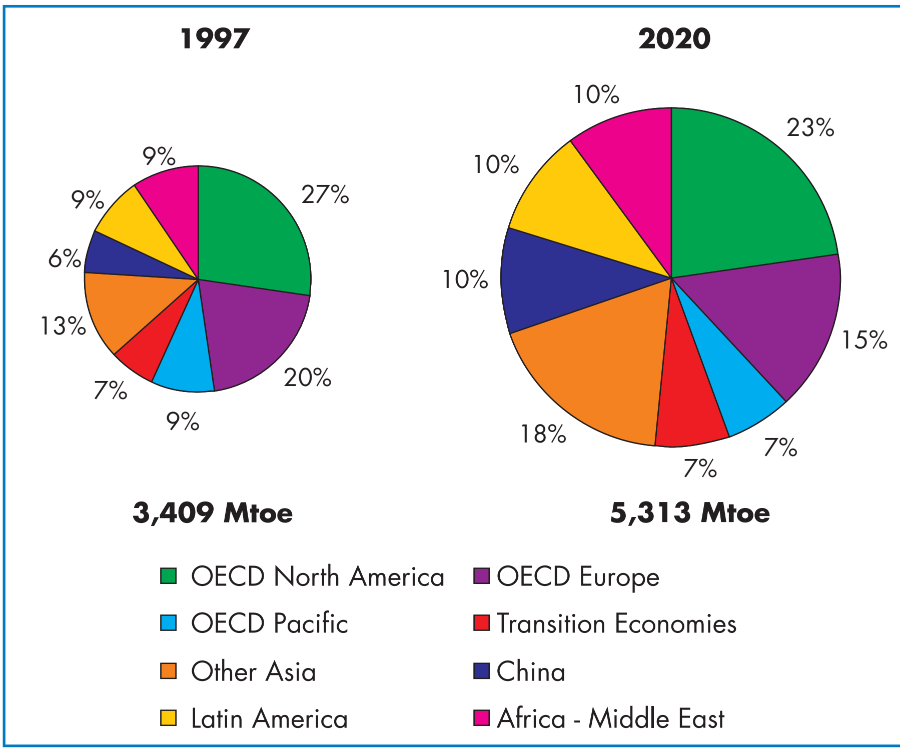
- Technology has lowered the costs of oil supply from unconventional sources. Given the enormous size of unconventional resources, further cost reductions could vastly improve the oil supply outlook. Analysts estimate that about 300 of the 2,500 billion barrels of oil in Canadian oil sands could be recoverable. This much oil would satisfy global oil demand, at current rates, for over 10 years. Once the initial capital cost of building an oil sand facility has been paid, production is reliable and the rate is insensitive to changes in the oil price.
- Improvements in the economics of converting gas or coal into oil could also lead to large increases in unconventional oil supplies. Global reserves of gas are huge, and their location is well known. Moreover, reducing the cost of transforming gaseous hydrocarbons into liquid form may increase effective reserves and so improve the security of oil supply.

Overview of Oil-Market Trends

Demand

Under the Reference Scenario assumptions of the *WEO 2000*, global primary oil demand is projected to increase from 74.5 mb/d in 1997 to 114.7 mb/d by 2020, an annual growth rate of 1.9% per year. Demand in non-OECD countries rises three times as fast as in the OECD, reaching 55% of total world oil consumption in 2020, up from 43% today (Figure 2.1). Non-OECD consumption of oil exceeds that of the OECD after 2010 and is 20% larger by 2020.

Figure 2.1: **Total World Primary Oil Demand by Region**



Note: Excluding international marine bunkers and stock changes.
Source: IEA (2000b).

Most of the expected incremental oil demand over the next two decades comes from the transport sector, where the possibilities for inter-fuel substitution are limited – especially in the short term. Transportation accounts for virtually all oil demand growth in the OECD and almost two-thirds elsewhere.

China and India alone will account for one-third of incremental oil demand in non-OECD countries. Primary oil demand is projected to grow by 4.4% a year in China and 4.5% in India.

Supply

Overall Supply Trends

World oil supply[1] is projected to grow from 75 mb/d in 1997 to 96 mb/d in 2010 and to 115 mb/d in 2020. Two major production trends are anticipated:

- Total non-OPEC supply matures and flattens after 2010. Russia and other transition economies, West Africa and Latin America are expected to contribute most to increases in non-OPEC supply. Deepwater offshore developments are expected to play an important role in the latter two regions, particularly in Angola and Brazil, as well as adding to production in the United States.
- Production in OPEC countries, especially the Middle East members, will increase more rapidly in the second half of the projection period.

The *WEO 2000* projections assume that world oil resources are sufficient to meet demand over the projection period. No peak in production is expected before 2020. Although oil fields in some regions are maturing, and their production will start or continue to decline, the resource base of the world as a whole is not a constraining factor. While no global "supply crunch" is expected, getting the oil resources out of the ground will require large and sustained capital investment, particularly in Middle East OPEC. The issue of investment in production is more urgent than that of adding to the reserve base. Table 2.1 shows the projected world oil balance.[2] While these numbers provide the basis for the supply and demand analysis, this study goes into more detail on factors influencing supply, and analyses recent trends in supply costs and production growth.

1. Including conventional and unconventional oil.
2. Assumptions and methodologies are described in *WEO 2000*. (IEA, 2000b)

Non-OPEC Production

Non-OPEC production is expected to grow from 42 mb/d in 1997 to 46.9 mb/d in 2010. In the second decade, however, production in many key non-OPEC countries will mature, and overall output is expected to level off, reaching 46.1 mb/d in 2020. OECD-area output (excluding Mexico) is projected to fall from 18 mb/d in 1997 to 15.7 mb/d in 2010 and to 13.1 mb/d in 2020.

Regional production trends vary considerably:

- Output in *North America*, determined largely by the United States, is expected to decline gradually to 9 mb/d in 2020. New deepwater fields coming onstream in the Gulf of Mexico will cause US production to rise in the medium term, but overall production is expected to decline after 2007 or so. Without additional major developments, Alaskan output would resume its long-term decline after several years of plateau, as some small and medium-sized new fields come onstream. Further growth in natural gas liquids[3] (NGL) production is expected to offset some of the decline in oil production. Recent policy developments resulting from the 2001 US National Energy Policy[4] review could lead to the opening of major areas that may add over 1 mb/d after 2010.[5] Canadian production is expected to rise steadily over the next decade, with considerable growth in unconventional oil, both from new synthetic crude projects and from major expansions of existing ones. Supply from Atlantic offshore fields is also expected to grow in the medium-term.
- In *OECD Europe*, production comes almost entirely from the North Sea, where output is expected to reach its peak early in this decade. It is expected to decline thereafter, reaching 3.5 mb/d in 2020. Norwegian supply will probably grow moderately before starting a gradual descent. The UK has fewer prospects for new development. While some new fields will undoubtedly be found, they are expected to be relatively small.
- In *OECD Pacific*, production, mostly coming from Australia, is expected to remain at about 0.8 mb/d until 2005 before declining to 0.5 mb/d in 2020. New fields in the Timor Sea have spurred

3. Natural gas liquids are liquid or liquefied hydrocarbons recovered from natural gas in separation facilities or gas processing plants.
4. US National Energy Policy Development Group (2001).
5. According to projections in EIA, 2000b.

Table 2.1: **World Oil Balance** (mb/d)

	1997	2010	2020	1997 – 2020*
Total Demand	**74.5**	**95.8**	**114.7**	**1.9**
OECD	***40.9***	***46.9***	***50***	***0.9***
North America	20.2	24	26.1	1.1
Europe	14.1	16	16.8	0.7
Pacific	6.5	7	7.1	0.4
Non-OECD	***30.1***	***45***	***60***	***3.1***
Transition economies	4.7	5.8	7.4	2
China	4.1	7.6	11	4.4
East Asia	6.4	10.1	13.6	3.3
South Asia	2.3	4.1	6.2	4.5
Latin America	6.1	8.7	10.9	2.5
Africa	2.1	3	3.9	2.7
Middle East	4.4	5.7	7	2.1
Bunkers and stock changes	3.6	3.9	4.6	1.1
Total Supply	**74.5**	**95.8**	**114.7**	**1.9**
Non-OPEC	***42***	***46.9***	***46.1***	***0.4***
OECD	18	15.7	13.1	–1.4
North America	10.6	9.9	9	–0.1
Europe	6.7	5.2	3.5	–2.7
Pacific	0.7	0.6	0.5	–1.3
Transition economies	7.4	10.3	12.3	2.2
Russia	6.1	7.1	7.9	1.1
Other transition economies	1.3	3.2	4.4	5.3
China	3.2	3	2.6	–1
India	0.8	0.5	0.4	–2.6
Other Asia	1.4	1.6	1.4	–0.1
Brazil	0.9	2.4	3.2	5
Other Latin America	5.7	6.8	6.8	0.7
Africa	2.7	4.8	4.8	2.5
Middle East	1.9	1.8	1.6	–0.8
OPEC	***29.8***	***44.1***	***61.8***	***3.2***
OPEC Middle East	19.5	30.5	46.7	3.9
Other OPEC	10.3	13.6	15.1	1.7
Unconventional Oil	1.3	2.7	4.2	5.4
Processing Gains	1.6	2.2	2.6	2.2
OPEC Share (%)	**40**	**46**	**54**	**1.3**
OPEC Middle East Share (%)	**26**	**32**	**41**	**2**

*Average annual growth rate, in per cent.
Source: IEA (2000b).

recent growth, but they will not offset the decline in production expected in the older Gippsland and Carnarvon Basins.

- The contribution of Russia and the other *transition economies* to non-OECD oil supply is expected to increase gradually over the projection period. Caspian production is likely to grow particularly fast. After bottoming out at about 7 mb/d in 1996, oil supply from these countries is projected to reach 10.3 mb/d in 2010 and 12.3 mb/d by 2020:

  – Russian output will grow steadily. The focus of capital spending and development-drilling is expected to shift away from enhancing existing reservoirs towards bringing new fields and reservoirs into production. With the policy assumptions in the *WEO 2000*, Russian production is projected to reach 7.9 mb/d by 2020, although strong production growth in the recent past indicates that Russia may exceed these projections.

  – Oil production in Kazakhstan is expected to double in the period to 2010 and to continue growing thereafter due to production from Tengiz, Karachaganak and the recently discovered Kashagan field. Oil transportation is a key factor in the outlook for Kazakhstan.

  – Output in Azerbaijan is projected to grow considerably in the next ten years. The Azerbaijani International Operating Consortium (AIOC) is expected to increase production to 800 kb/d by the end of the decade.

- Oil production in *Latin America* is projected to grow during the next two decades, from 7.2 mb/d currently to just over 9 mb/d in 2010 and slightly more than 10 mb/d by 2020. Production from large new deepwater fields in Brazil will account for much of the growth. Brazilian production is projected to climb from 0.9 mb/d in 1997 to 2.4 mb/d over the next decade and to 3.2 mb/d in 2020. Mexican oil supply is projected to grow for the next half-decade then level out.

- Production increases are expected in *Africa*. Output is projected to rise from 3 mb/d this year to 4.8 mb/d in 2010 and remain at around that figure until 2020, with most oil coming from the West African offshore area especially large deepwater fields in Angola.

- Oil output in East and South Asia is mature and expected to fall over the next two decades, with few major developments in the offing. China, however, will stave off overall declines until after 2005, due once again to the offshore sector. Current Chinese production of 3.3 mb/d will decline slightly to 3 mb/d in 2010 and to 2.6 mb/d at the end of the projection period.

OPEC Production

The *WEO 2000* assumes that OPEC production will satisfy the portion of world oil demand not met by non-OPEC output. Therefore, OPEC supply (including crude, natural-gas liquids and condensate) is projected to increase from 29.8 mb/d in 1997 to 44.1 mb/d in 2010 and to 61.8 mb/d in 2020.

Growth in Middle East OPEC output is particularly important in the period 2010-2020. Of the 18.9 mb/d growth in worldwide oil demand projected during this decade, Middle East OPEC is expected to fulfil 16.2 mb/d, with only 1.5 mb/d coming from other OPEC producers. There is little doubt that the Middle East OPEC countries — Saudi Arabia, Iran, Iraq, Kuwait, the UAE, and Qatar — have the reserves to cover incremental global oil demand. Nevertheless, these countries will have to attract sufficient, sustained and timely investment in order to increase their production capacity.

Natural Gas Liquids

Natural gas liquids (NGL) are included in the outlook for conventional oil production. World NGL production has grown by over 1.8 mb/d, or 33% in the last 10 years, to reach 7.2 mb/d in 2000.[6] Of this figure, the OECD produced 3.6 mb/d and OPEC accounted for 2.7 mb/d. NGL production is expected to continue to increase, as a result of its association with increasing gas production and the significant remaining reserves.

The largest NGL producer is the United States, where it has been an important factor in offsetting decline in other conventional oil production. NGL production in 2000 was 1.9 mb/d, representing over 23% of total oil production.[7] The US Energy Information Administration (EIA) expects NGL production to grow to 2.9 mb/d by 2020, when it will represent over 30% of total oil production.[8]

6. IEA (2001b) and IEA databases.
7. EIA (2001b).
8. EIA (2001a).

Unconventional Oil Production

Unconventional oil production is projected to grow from 1.3 mb/d in 1997 to 2.7 mb/d in 2010 and to 4.2 mb/d in 2020. Most types of unconventional production are economic at the prices assumed in the *WEO 2000* and will continue to be so. As a result, projects are expected to develop in anticipation of market needs. The gains come primarily from synthetics crude production from oil sands in the Canadian province of Alberta, and from the Orinoco extra-heavy crude oil belt in Venezuela.

Trade and Import Dependency

The projections for global oil demand and production described above will generate a big increase in international trade to meet the widening gap between consumption and output in many parts of the world. Table 2.2 details the projected net imports and exports of each major region. Inter-regional trade is expected to increase from 28 mb/d in 1997 to over 60 mb/d in 2020.[9]

Table 2.2: **Projected Net Oil Imports** (mb/d)

	1997	2010	2020
OECD North America	9.0	12.6	15.2
OECD Europe	7.4	10.8	13.3
OECD Pacific	5.7	6.4	6.6
Transition economies	–2.8	–4.5	–4.9
Africa	–6.1	–9.4	–9.5
China	0.9	4.6	8.5
Other Asia	4.9	10.8	16.7
Latin America	–4.1	–5.4	–4.6
Middle East	–17.0	–26.6	–41.3

Note: Negative numbers indicate net exports.
Source: IEA (2000b).

Regions that depend on imports to meet a major part of their oil needs — notably the three OECD regions and non-OECD Asia — will become even more dependent on imports over the projection period, both in

9. Total international trade is greater than these figures suggest because of trade within each region and re-export between regions.

absolute terms and as a proportion of their total oil consumption (Table 2.3).

In nominal terms, the increase in trade flows to non-OECD Asia exceeds those to all the OECD regions combined. This means that an increasing proportion of OPEC production, especially from the Middle East, will go to meet Asian demand.

Table 2.3: **Oil Import Dependence** (per cent)

	1997	**2010**	**2020**
North America	44.6	52.4	58.0
Europe	52.5	67.2	79.0
Pacific	88.8	91.5	92.4
OECD	**54.3**	**63.3**	**70.0**
China	22.3	61.0	76.9
East Asia	53.7	70.5	80.7
India	57.4	85.2	91.6
Rest of South Asia	87.2	95.1	96.1

Note: Oil import dependence is defined as the ratio of net oil imports over total primary oil demand.
Source: IEA (2000b).

Key Factors Affecting Oil Supply Prospects

Resources and Reserves

Conventional

There is considerable uncertainty about the volume of oil that exists worldwide and the amount of this resource that can ultimately be recovered. Recent studies have yielded markedly different results according to the judgement of the assessor and the time when the assessment was made. Table 2.4 summarises estimates for proven reserves of crude oil and natural gas liquids (NGL) from several prominent studies. All the assessments indicate that there are sufficient recoverable reserves of oil to meet expected increases in demand. Based on the *WEO 2000* Reference Scenario projections of oil supply, the 10 years of expected production from the end of year 2000 to 2010 would require approximately 320 billion barrels of oil. The 20 years of expected oil production after the end of 2000 would require just over 700 billion barrels of reserves.

Table 2.4: **Proven Crude Oil and NGL Reserve Assessments**
(billion barrels)

Source	Reserves	Effective Date	Assessment Date
IHS Energy	1,100	End 2000	July 2001
OPEC Secretariat	1,078	End 2000	August 2001
World Energy Council	1,051	End 1999	October 2001
Oil and Gas Journal	1,028	1 January 2001	December 2000
World Oil	1,003	End 2000	August 2001
USGS 2000	960	1 January 1996	June 2000
ODAC (Campbell)*	845	End 2000	July 2001

* Oil Depletion Analysis Centre (ODAC), Campbell presentation at European Fuel Cell Forum, Fuel Cell 2001 conference in Lucerne, Switzerland, 2-6 July 2001.
Notes: Reserves are mean proven remaining reserves only. World Oil reserves estimate excludes NGL. ODAC reserves estimate excludes NGL, gas condensates, deepwater oil (over 500 metres water depth), polar oil. The world reserves data in the USGS 2000 assessment reflect only those parts of the world actually assessed.

Comparison of the various assessments of reserves is complicated by differences in the definition of unconventional oil. Some commentators consider deepwater oil (occurring in water depths greater than 500 metres) as unconventional because of the difficulties of extracting it. With continued technological development over the last few years, and the considerable amount of deepwater exploration, prospects for deepwater reserves have increased significantly. The reserves estimates in Table 2.4 include only conventional oil reserves. The IEA's definition of conventional and unconventional oil is provided in Box 2.1. Other discrepancies can result from the assessment methodology and the data that was available at the time the assessment was prepared. If there were no growth in reserves, then remaining reserves would decrease over time by the amount of oil that is produced. Current global oil production is about 28 billion barrels per year, so an assessment of reserves with an effective date of end 2000 should be 28 billion barrels less than it was at the end of 1999. In practice, there has been little decline in reserves estimates, with most assessments *increasing* compared with the previous year. The evolution of USGS assessments is discussed below.

Box 2.1: **IEA Definitions of Conventional and Unconventional Oil**

Oil is defined to include all liquid hydrocarbon fuels and it is accounted for at the product level. Sources include NGL and condensates, refinery processing gains and the production of conventional and unconventional oil. Oil is considered unconventional if it is not produced from underground hydrocarbon reservoirs by means of production wells or if it needs additional processing to produce synthetic crude. More specifically, unconventional oil production is based on the IEA's Oil Market Report (OMR) definitions and includes the following sources:

- Oil shales
- Oil sands-based synthetic crudes and derivative products (heavy oil, Orimulsion®)
- Coal-based liquid supplies
- Biomass-based liquid supplies
- Gas to Liquid (GTL) - liquids arising from chemical processing of gas

Unconventional oil does not include liquefied natural gas (LNG), which is liquefied for transportation but re-converted to gas before final consumption.

In 2000, total oil supply of 76.7 mb/d included 1.3 mb/d of unconventional oil and 1.7 mb/d of refinery processing gains.[10]

The most authoritative source of data on global oil resources, including both proven reserves and undiscovered resources, is the US Geological Survey's *World Petroleum Assessment 2000*,[11] which was the reference used in *WEO 2000*. It is the latest assessment of conventional world oil and gas resources by the US Geological Survey (USGS) — and their first such study since 1994. The report includes the results of a geologically-based assessment of the world's undiscovered conventional petroleum resources that could be added to reserves in the 30 years from 1995 to 2025. The reference date for the survey is 1 January 1996.

The USGS estimates that worldwide "ultimate recoverable resources" of conventional oil and NGL total 3,345 billion barrels (Table 2.5).

10. IEA (2001a).
11. USGS (2000).

Ultimate recoverable resources include cumulative production to date, identified remaining reserves, undiscovered recoverable resources and estimates of "reserve growth" in existing fields. Such reserve growth refers to the increases in estimated sizes of oil fields that typically occur as they are developed and produced. It accounts for around 28% of the estimated remaining ultimate recoverable resources,[12] whereas remaining reserves and undiscovered resources account for about 36% each.

Table 2.5: **USGS Estimates of Global Oil and NGL Resources**
(billion barrels)

	Oil	NGL*	Total
Undiscovered recoverable resources	732	207	939
Mean reserve growth	688	42	730
Mean remaining reserves	891	68	959
Cumulative production	710	7	717
Ultimate recoverable resources	**3,021**	**324**	**3,345**

*NGL volumes for the US are included in the oil figures.
Note: World reserve and cumulative production data reflect only those parts of the world actually assessed.
Source: USGS (2000).

Global oil and NGL reserves are far from evenly distributed. Figure 2.2 shows the concentration of reserves in OPEC countries in 1996 and the production shares for 1997.

12. Remaining ultimate recoverable resources is the sum of remaining reserves, reserve growth and undiscovered recoverable resources.

Box 2.2: **Resource Assessment Terms**

Cumulative Oil and NGL Production: Reported cumulative volume of oil and NGL that has been produced to the reference date.

Remaining Oil and NGL Reserves: Volume of oil and NGL in discovered fields that has not yet been produced.

Reserve Growth: The increases in known oil and NGL volumes that commonly occur as oil and NGL fields are developed and produced.

Undiscovered Oil and NGL Recoverable Resources: Resources postulated from geologic information and theory to exist outside of known fields.

Ultimate Recoverable Oil and NGL Resources: The sum of the mean undiscovered resources, the mean reserve growth, the mean remaining reserves and the cumulative production.

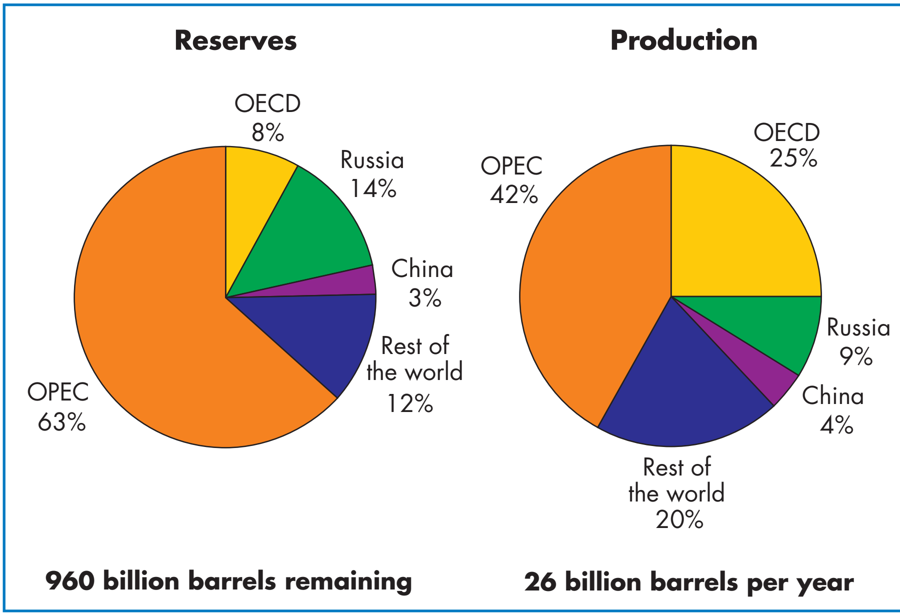
The terms "oil reserves" and "oil resources" refer to the fact that some oil in the ground has been discovered and can be produced economically, and some has not yet been discovered, but is thought likely to exist. Oil that has been discovered and is expected to be economically producible is called a reserve. Oil that is thought to exist, and is expected to become economically recoverable, is called a resource.

The USGS's estimates of available reserves and resources have increased over time (Figure 2.3). This is primarily due to:

- increases in cumulative oil production,
- additional oil exploration activity,
- availability of more and better quality data,
- development and deployment of advanced technology to improve the ability to find and produce oil.

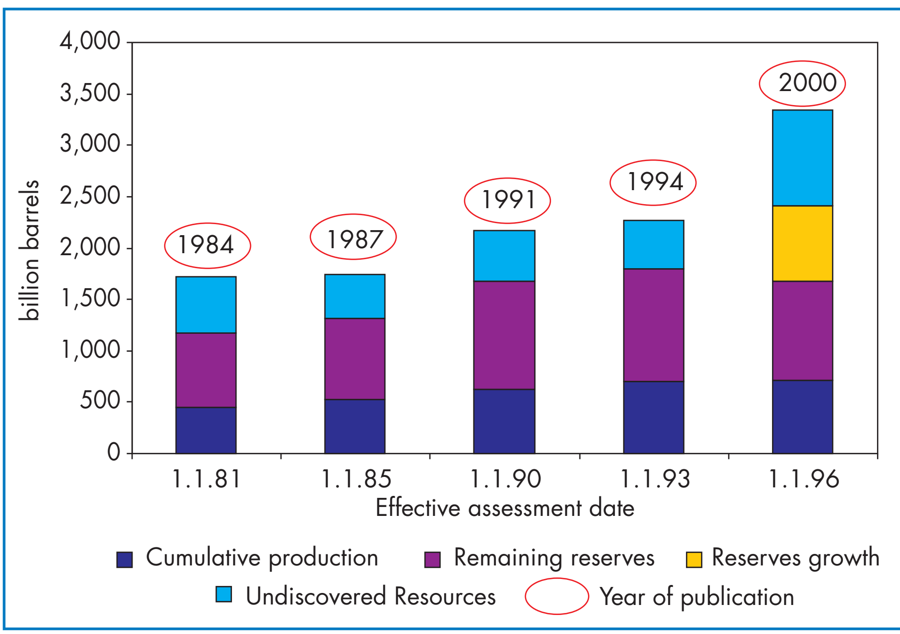
Estimation of resources involves judgements on finding and development costs, oil prices and technological development and deployment. The assessments rely heavily on the availability of geological, geophysical and production data acquired by organisations exploring for and producing oil. When considering the precision of this data, it should

Figure 2.2: **World Crude Oil and NGL Reserves and Production**



Source: Reserves as of 1 January 1996 (USGS, 2000) and production in 1997 excluding bunkers and stock changes (IEA, 2000b).

Figure 2.3: **Historical Evolution of USGS Resource Estimates**



Note: USGS 2000 world reserve and cumulative production data reflect only those parts of the world actually assessed. For a detailed description of the change in methodology to add a reserve growth category, see USGS (2000).
Source: USGS (2000).

be recalled that the activities that may lead to a confident increase in the assessment of total world oil reserves involve additional expense for the oil-producing organisations. Since proven reserves are in essence "on-the-shelf inventory", expenditure to identify additional reserves may be deferred if existing reserves are deemed sufficient. Similarly, gathering of other production data for improving the world's understanding of ultimate recoverable reserves and resources may be deferred.

For many major oil companies, a key indicator of the sufficiency of remaining oil reserves is the reserves-to-production (R/P) ratio, or reserves divided by annual production. Table 2.6 shows that R/P ratios for many major producing countries are greater than 50 showing little need to increase the precision of the reserves assessment. However, a decline in production rates and potential issues associated with the geographic location of available supplies may provide incentives to find additional reserves or to boost reserves through enhanced recovery in certain areas. Nonetheless, the potential for reduction in oil supply costs ensures that considerable uncertainty will remain due to changing expectations of what is economically recoverable.

Impact of Technology on Reserve Growth

Over the past ten years, the major international oil companies have, on average, replaced 100% of the oil and gas they have produced. Just over half of majors' oil and gas reserve bookings have come from discovery and extensions. Almost half of oil and gas reserve replacement has come from upward revisions of reserves in existing fields and improved recovery.[13] BP's Prudhoe Bay field in Alaska is expected to produce more than 4 billion barrels of oil on top of the 8 billion barrels envisaged in 1977 – a 50% increase in field size. As previously discussed, the 2000 USGS study represents a significant increase in reserves and resources. A considerable part of this increase comes from "reserve growth", accounting for 612 billion barrels or 44% of the known volume of oil (1,398 billion barrels).

In the United States and Canada, experience shows that estimates of the sizes (cumulative production plus remaining reserves) of oil and gas fields made at any particular point in time are commonly too low.[14]

13. Michael Smith, BP, Presentation to the IEA Advisory Group on Oil and Gas Technology, Paris, 1 June 2001.
14. See Arrington (1960) and Attanasi and Root (1994).

Table 2.6: **Reserves, Resources and Production by Country**

Rank	**Country**	**Cumulative Production** (billion barrels)	**Mean Remaining Reserves** (billion barrels)	**Mean Undiscovered Resources** (billion barrels)	**Reserves to Production Ratio*** (in years)
1	Saudi Arabia	73	221	136	76
2	Russia	97	137	115	58
3	Iraq	22	78	51	83
4	Iran	34	76	67	56
5	UAE	16	59	10	72
6	Kuwait	26	55	4	85
7	US	171	32	83	11
8	Venezuela	46	30	24	29
9	Libya	14	25	9	49
10	China	24	25	17	21
11	Mexico	22	22	23	18
12	Nigeria	16	20	43	27
13	Kazakhstan	4	20	25	79
14	Norway	9	16	23	13
15	Algeria	10	15	10	50
16	Qatar	5	15	5	59
17	UK	14	13	7	13
18	Indonesia	15	10	10	22
19	Brazil	2	9	55	16
20	Kuwait/Saudi Arabia Neutral Zone	5	8	0	37
	Others	91	73	220	11
	Total	718	959	939	35

* Production in 2000 is used for the reserves to production ratio.
Note: Countries are ranked by mean remaining reserves. Reserves are from USGS 2000 effective 1/1/96. Reserves and cumulative production data reflect only for those parts of the country actually assessed.
Source: USGS (2000), IEA.

As years pass, successive size estimates of *groups of fields* usually increase collectively, even though the size changes of individual fields through time are extremely variable. The term "reserve growth" as used here, which is synonymous with "field growth", refers to the increases in estimated sizes of fields that typically occur through time as oil and gas fields are developed and produced. Although only remaining reserves actually increase in volume, their increase is generally considered to be proportional to the total size of the field. Reserve growth is a major component—perhaps *the* major component—of remaining oil reserves in mature areas such as the US.[15]

Technology will play a key role in reserve growth. The average size of newly discovered fields is declining, and giant fields are being discovered less frequently, so it is becoming more difficult to replace reserves. While we may have already passed the peak of discovery for major oil accumulations, the level of remaining reserves can be increased through improvement in the amount of oil that is recovered. Table 2.7 illustrates how the recoverable reserves change with the recovery factor, assuming a fixed stock of conventional oil in place of 6,000 billion barrels. Each 1% improvement in the recovery factor adds 60 billion barrels of oil to reserves, equivalent to more than two years demand at current rates, and worth over a trillion dollars at current prices.

Table 2.7: **Assumed Ultimate Conventional Oil Resources** (billion barrels)

Recovery factor	Ultimate oil reserves based on a fixed oil stock in place of 6 trillion barrels	Increase from base of 1,800 billion barrels from new information and technology
30%	1,800	0
33%	2,000	200
38%	2,300	500
50%	3,000	1,200

Source: IEA (1998).

The impact of new technology on oil and gas supply from the relatively mature North West European Continental Shelf (NWECS) was analysed by a European Commission sponsored study produced in November 1999.[16] The data collected covered new and incremental developments committed between January 1990 and December 1997. The study concluded that technology increased oil and NGL reserves by nearly 9 billion barrels (Table 2.8).

15. See Gautier et al. (1995); USGS (1995); and Schmoker and Attanasi (1997).
16. CEC (1999).

Table 2.8: **Reserve Increases Due to the Application of Technology to North West European Continental Shelf Oil and Gas Developments** (oil in million barrels, gas in billion cubic metres)

	New fields made possible		**Increased reserves existing fields**		**Total**	
	Oil	**Gas**	**Oil**	**Gas**	**Oil**	**Gas**
UK	2,969	284	849	145	3,817	429
Norway	3,042	78	1,515	0	4,556	78
Denmark	171	13	301	47	473	60
Total impact on reserves	6,182	374	2,664	192	8,846	567

Source: CEC (1999).

The study found that 75% of the gains were attributable to innovations in three key areas: drilling, seismic exploration and floating/subsea production in new fields (Table 2.9).

Table 2.9: **Impact of New Technologies on Reserves** (% change)

	UK		**Norway**		**Denmark**		**Overall**
	Liquids	**Gas**	**Liquids**	**Gas**	**Liquids**	**Gas**	
Subsea	3.7	3.8	4.8	8.4	0.0	0.0	4.1
Drilling	28.1	38.5	37.7	42.6	81.4	71.1	37.5
IOR	3.2	11.8	4.4	2.1	5.6	5.3	5.6
Platform	2.1	3.3	1.9	2.4	1.3	4.0	2.4
Seismic	19.8	12.4	32.2	32.9	10.8	12.7	22.5
Floating	13.5	2.0	17.6	6.2	0.0	0.0	10.2
Other	18.6	19.3	0.3	0.0	0.0	0.0	10.3
Cost Reduction Initiatives	11.0	8.9	4.0	5.4	0.9	7.0	7.4

Note: IOR is Improved Oil Recovery. Overall refers to oil, liquid and gas converted to boe.
Source: CEC (1999).

The study's authors expect that a further 7 billion boe of European reserves can be made accessible by technological progress by 2005, with a possible additional 12 billion boe thereafter. The conclusion, that the future reserves and production from the North West European Continental Shelf, will be heavily influenced by the level of Research and Technology Development (RTD), is fully supported by the findings of the Institut Francais du Pétrole.[17] The low, probable and high production scenarios are compared with the North Sea Production Forecast of 1983 in Figure 2.4, showing the importance of RTD in increasing production from the North West European Continental Shelf.

Unconventional Oil

There are enormous volumes of unconventional ultra-heavy oil and bitumen in Canada and Venezuela. Exploitation of this oil, however, depends critically on cost of extraction and the price of the oil.

The National Energy Board of Canada estimates that about 300 billion barrels of the 2.5 trillion barrels of crude bitumen in the country may be ultimately recoverable.[18] In Venezuela, Bitumenes Orinoco, S.A. (BITOR) estimates that over 1.2 trillion barrels of bitumen exist in the Orinoco belt, of which about 270 billion barrels are thought to be economically recoverable with current technology.[19]

The volume of *liquid* hydrocarbon could be increased by improvements in gas-to-liquids (GTL) or coal-to-liquids technology that cost-effectively transforms gaseous or solid hydrocarbon into liquid hydrocarbon.

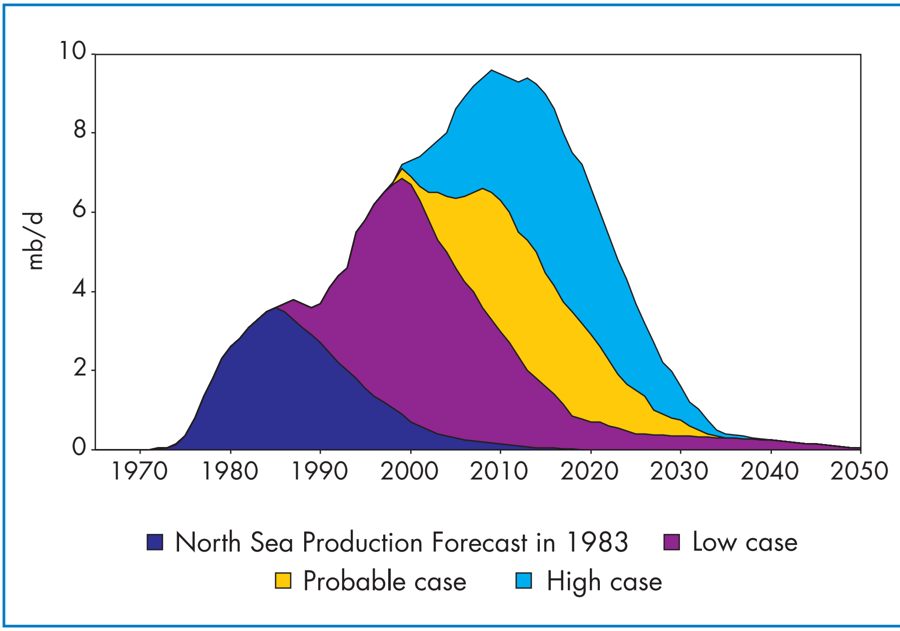
Supply Costs and Enhanced Productivity

Overall Comparison of Costs of Oil Supply

Oil supply costs have fallen considerably in the last 20 years. New sources of conventional oil supply from non-OPEC countries and unconventional oil such as bitumen and synthetic crude have become increasingly competitive with OPEC supplies on a cost basis. Furthermore, technological progress is expected to reduce the cost of GTL conversion, improving the economics of supplying liquid hydrocarbon fuels from gas.

17. CEC (1999).
18. National Energy Board (2000).
19. http://www.orimulsionfuel.com/origin/reserve/reserve.html.

Figure 2.4: **Evolution of North West European Continental Shelf Production Forecasts with Research and Technology (1997 versus 1983)**



Note: Under the high case, the daily production is expected to peak at 9.5 mb/d around 2010. Under the probable case, production is kept at 6-7 mb/d, but for much longer than in the low case. These cases can be compared with Table 2.1 where OECD Europe production is projected to be 5.2 mb/d in 2010 and 3.5 mb/d in 2020.
Source: CEC (1999).

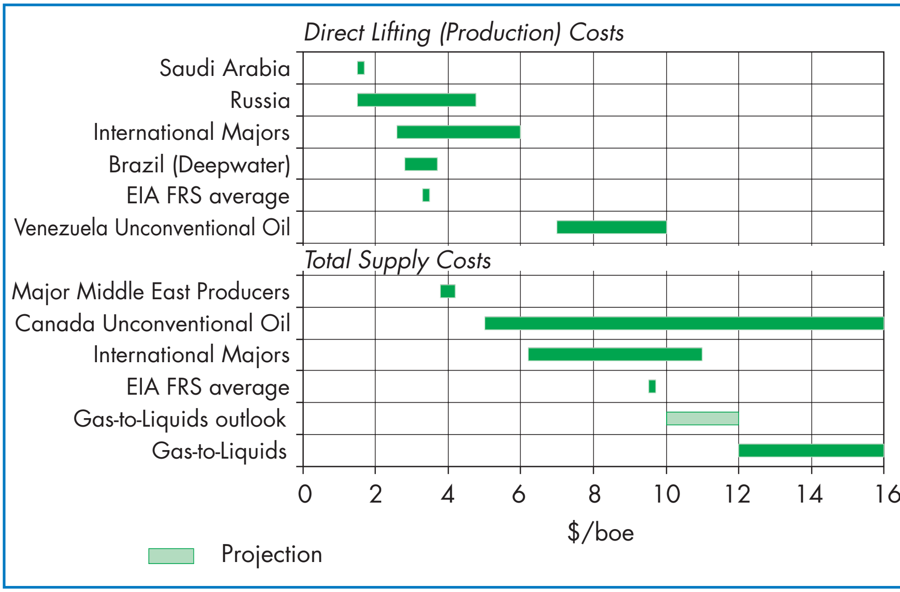
Development and deployment of new technology, improvements in productivity due to the widespread adoption of information and communication technology and further global rationalisation of the industry structure would further reduce supply cost. Figure 2.5 compares estimates of production costs for selected sources.

The direct lifting (production) costs include labour, maintenance and repairs, materials and supplies and fuel consumed. The lifting costs per barrel are the direct lifting costs plus production tax expense. The direct comparison of these costs is complicated by differences in the classification of expenses and accounting methods, necessitating some adjustment to the data to give comparable supply costs in Figure 2.5.[20] The production-tax cost for state-owned oil production and the specific allocation of expenses

20. For discussion of the difficulties in comparing costs, see Prudential Financial (2001).

between company and state complicate the comparison of lifting costs of state-owned enterprises with those of the private sector. For certain unconventional sources such as extra-heavy crude, additional costs are incurred for upgrading, which is taken into account in the cost comparison.

Figure 2.5: **Oil Supply Costs**



Note: EIA FRS refers to the EIA Financial Reporting System companies.[21] The direct lifting (production) costs per barrel are those costs incurred during production to operate and maintain wells and related equipment. The total supply costs include direct lifting costs, production costs and finding and development costs. For GTL, the output is a refined product rather than crude oil. The cost data do not reflect the differing values of the crude grades produced.
Sources: Prince Faisal Bin Turki Bin Abdul Aziz Al-Sa'ud speech, The Development of Middle East Energy conference, London 12th February, 2001; Oil company reports and presentations; Troika Dialog; Prudential Financial Research; EIA, National Energy Board, Canada; Syntroleum Corporation, IEA analysis.

The comparison shows that the lowest lifting costs are those for conventional oil production in Saudi Arabia. Production costs in other major Gulf countries are similar to those in Saudi Arabia. Russian oil-production costs approach those of the Middle East, following cost reductions in recent years due to the application of technology and more efficient working practices, as well as the effect of the rouble devaluation.

21. EIA (2001c).

The major oil companies have highly-competitive production costs, largely due to effective management of expenses in areas with maturing production as well as in new areas of production. Production costs for deepwater production in Brazil and elsewhere are competitive with other conventional production due to substantial improvements in deepwater technology. While Venezuelan unconventional oil production costs are higher than those for conventional oil, these projects are intended to be profitable when the Venezuelan export basket oil price is at $10 per barrel,[22] and take advantage of the considerable size of discovered unconventional oil volumes.

Figure 2.5 indicates that major Middle East producers have the lowest total supply costs.[23] However, the published cost reduction targets of the international major oil companies indicate that total supply costs are expected to continue to fall to about $4 per boe in the next few years.

The costs of unconventional oil production in Canada have declined considerably and now make synthetic crude from oil sands economic at high oil prices. It is expected that these costs will continue to fall, although they are linked to the price of natural gas and investment is dependent upon expectations of demand for synthetic crude. Similarly, the costs of synthetic crude production from the Orinoco belt in Venezuela have fallen with the development and deployment of new technology and the continuous improvement in extra-heavy crude processing.

The cost for producing oil products from gas is also in a range where investment is beginning to take place. GTL technology is promising from a cost perspective. It may also present additional advantages related to the environment or energy security. These benefits could encourage favourable tax treatment, indicating that unconventional oil supply costs may be influenced by policies relating to the cost of associated carbon dioxide emissions. GTL research already receives government funding in the United States.[24] Further reductions in the costs associated with GTL technology are expected from research and development on forthcoming operating projects.

22. *Petroleum Argus*, "Heavy Crude Benefits Overstated", 12 July 2001.
23. ENI (2001).
24. The US Department of Energy awarded a grant of $16 million on 24 July, 2001 for a GTL demonstration project.

Conventional Oil Supply Costs[25]

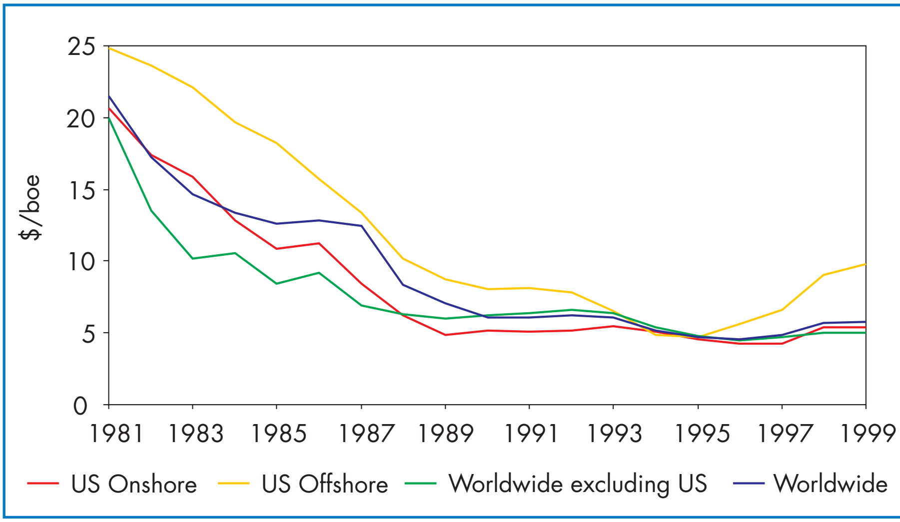
Worldwide finding and development (F&D) costs per barrel of oil equivalent (boe) declined from an average of about $21 in the three-year period 1979 to 1981 to under $6 in 1997-1999, according to EIA data (Figure 2.6). The decline in F&D costs has moderated in the 1990's, largely due to the increasing costs of finding and developing reserves offshore in the US. Since oil and gas resources are finite, and the larger, more cost-effective fields are normally found and developed first, F&D costs should be expected to rise with time, except to the extent that they are offset by efficiency and technology gains. The sharp decline in costs over the past 20 years points to considerable improvements within the oil and gas industry. This is explained partly by a fall in the number of dry wells, i.e. a well that does not encounter hydrocarbons (Figure 2.7). The success rate of encountering hydrocarbons with an exploration or development well has risen from around 80% in the late 1970s to over 90% in the late 1990s. Furthermore, the absolute number of dry wells drilled by the EIA Financial Reporting System companies has fallen from 1,907 in 1977 to 521 in 1999, representing considerable savings in exploration and development expenditure.

Advances in the development and deployment of technology have contributed to the increased percentage drilling success rate and the reduction in the total number of dry holes. Principal among these technological developments has been the application of vastly increased computing power to geophysical and geological interpretation. This has further stimulated the development of geophysical data-acquisition, resulting in lower data acquisition costs and improved data quality. The technological advances in seismic technology are described in Box 2.3.

Further developments in geophysical acquisition and interpretation, including 3D modelling and reservoir simulation, will lead to a much better understanding of the reservoir and will reduce both F&D costs and lifting costs. It is expected that by 2010, this technology, together with the development and deployment of sensors underground in and around the reservoir, will lead to real-time reservoir management. This will bring improvements in cost, efficiency and reliability of hydrocarbon extraction. Since the equipment needs to be installed underground, this technology is

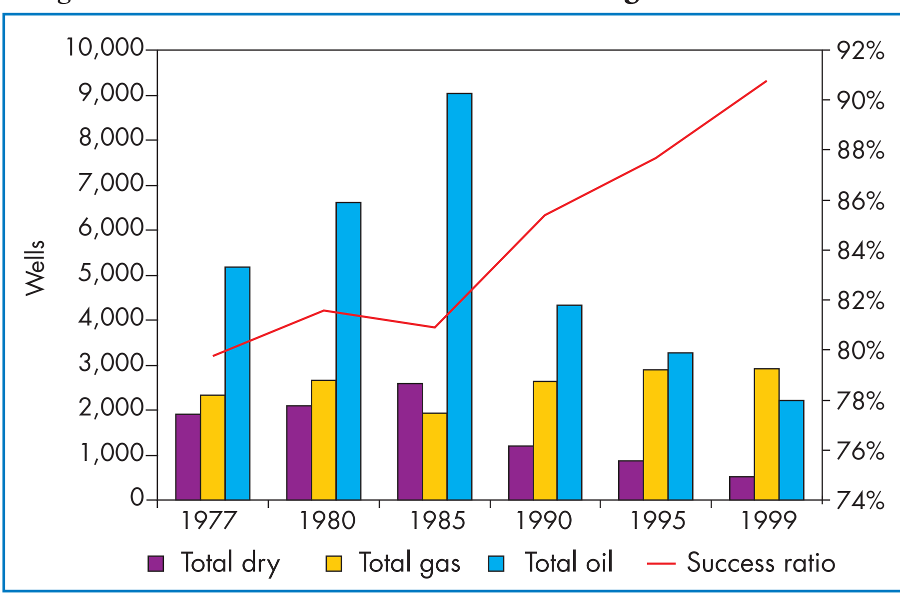
25. The comparison of trends in exploration, development and production costs is based primarily on data collected by the EIA for major US based energy producers (EIA, 2001a). Upstream costs are divided in two categories: finding and development costs (i.e the cost of adding crude oil and NGL (and gas) reserves via exploration and development activity) and lifting or production costs (i.e. out-of-pocket costs to operate and maintain wells and related equipment and facilities).

Figure 2.6: **Trends in Finding & Development Costs, Three-Year Moving Averages, 1979-1981 to 1997-1999**



Note: Data is from the EIA Financial Reporting System companies.
Source: EIA, IEA analysis.

Figure 2.7: **Trends in Oil and Gas Well Drilling and Success Ratio**



Note: Data is from the EIA Financial Reporting System companies. Drilling success ratio is defined as total oil and gas wells divided by total wells drilled.
Source: EIA, IEA analysis.

easier to apply in new wells drilled during new-field developments than in existing fields.

Box 2.3: **Seismic Developments**

The aim of 4-dimensional (4D) seismic measurements is to allow oil companies to extract more oil and gas from the underground reservoir. Optimal oil extraction requires up-to-date information on the rate of oil depletion throughout the entire reservoir volume. Access to the latest data on fluid distribution in a reservoir and knowledge of how the distribution is changing with time allow engineers to develop cost-effective strategies to produce the most oil out of every field with the lowest possible risk.

Time-lapse logging of fluid saturation can show which zones are contributing to production and which are watering out or being bypassed. Permanent downhole sensors provide continual observations of pressure, temperature and other aspects of reservoir performance. These measurements supply crucial information about fluid behaviour at the well location, but their interpretation needs to be refined with information about the vast inter-well regions. 3-dimensional (3D) seismic measurements have routinely been relied on to provide inter-well data. Developments in seismic interpretation have led to the extension of seismic techniques beyond conventional use in reservoir mapping to the identification of the type of fluid or gas present in underground reservoirs. Taking 3D seismic images of the reservoir at different points in time, following periods of oil production (collectively termed 4D seismic), can map the movement of fluids and gas in a producing reservoir. 4D seismic images can thereby supplement the predictions of reservoir parameters offered by the reservoir simulator.

In a further development of seismic technology, multicomponent or 4C seismic data acquisition techniques are expected to yield far more information about the subsurface reservoir rock and fluid systems. 4C seismic involves the collection of far more data about the characteristics of the sound wave that passes through the ground. This could lead to the identification of additional reserves and assist in optimising both the production rate and the recovery of the maximum possible amount of oil from the reservoir. It should also lead to a better understanding of the production decline rate.

The recent increase in three-year average F&D costs for the offshore United States from about $5/boe in the mid-1990s to $9.55/boe today, reflects the movement of exploration and development activities to deeper water in the Gulf of Mexico.[26] More recent data suggest that these costs will decline in the future, as technology continues to be developed and deployed and as companies gain more experience in operating in very deep water.

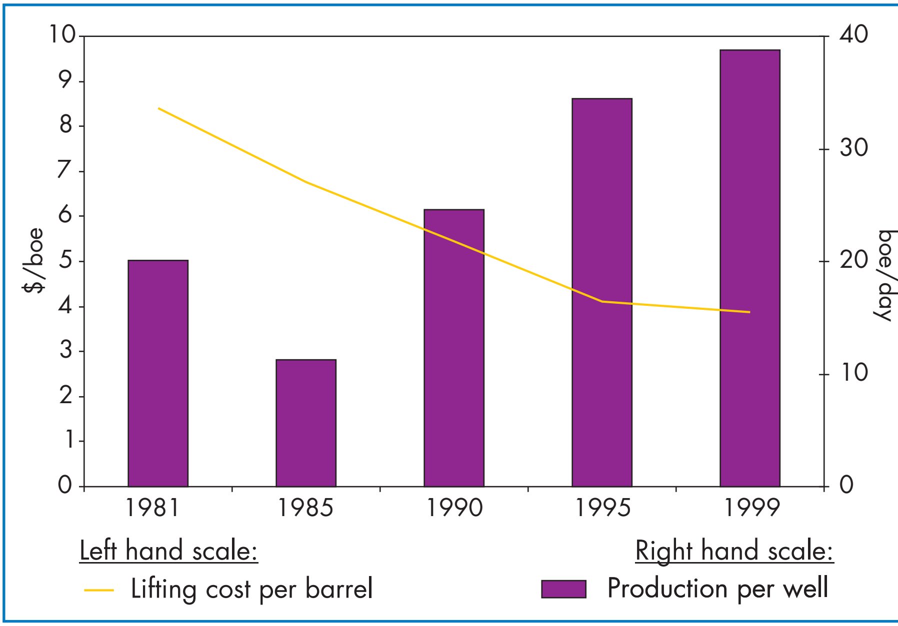
Worldwide lifting costs have fallen by over half from $8.40/boe in 1981 to $3.87/boe in 1999 (Figure 2.8). Increasing oil production from lower cost regions such as the Middle East and Russia would reduce the overall average supply costs. Data for five major Russian companies responsible for 4.2 mb/d of production, show lifting costs in 2000 varying between $1.5 and $3/barrel, with an average of $2.24. This demonstrates the increasing cost competitiveness of new Russian oil supplies, especially when expressed in dollars.

Increases in lifting costs in old, expensive production areas can be offset if the oil and gas industry continues to invest in the development and deployment of advanced technology to increase productivity. BP expects the reduction in lifting costs for its operations to continue to decline by between 2% to 4% per annum for the foreseeable future. The company's lifting costs declined from $3.60 to $2.70 per boe in the decade to 1999.[27] Higher production per well will contribute to lower production costs. Horizontal wells and multi-lateral wells – wells with multiple branches into the reservoir, will enhance this trend. The addition of sensors in and around the reservoir and underground control of production coupled with real-time reservoir management are also expected to bring much better production planning. Expensive loss or choking back of production, due to individual well problems or field-production issues, can be monitored and remedial action taken to maintain optimal oil production.

In the near term, the greatest potential for reducing total supply costs comes from technology that improves identification of reservoir characteristics, such as improvement in seismic techniques, as well as developments in drilling and production engineering. Important factors that have increased the forecasts of oil production are:

26. EIA (2001c).
27. BP Strategy Presentation, Dick Olver, July 2000.
http://www.bp.com/centres/investor/objectives/strat_pres_00/upstream.asp

Figure 2.8: **Lifting Costs and Production per Well**



Source: EIA, IEA analysis.

- optimisation of oil reservoir development and production plans as a result of technological development enabling better information ahead of decision-making;
- changes in production strategies and the use of specific measures to improve recovery of oil resources;
- under-estimation of the size of the reservoirs at the early stages of development;
- technology that has allowed the identification and production of smaller oil reservoirs that are found near, and added to, existing production facilities.

Despite the number of factors involved, technology is viewed as being the main contributing factor behind the improvements in oil production from major reservoirs.

Further significant advances in upstream technology may be achieved in the longer term (Box 2.4). How rapidly these are realised will depend to a large degree on the level and success of R&D activity. But there are signs that both government and corporate (oil company and contractor/service company) spending on upstream oil and gas R&D has fallen over the past decade, which could slow the pace of technology-driven cost reductions to some degree.[28]

Box 2.4: **Outlook for Upstream Oil and Gas Technologies under Development**

Examples of innovative solutions currently under development that could be deployed in the next decade or so include:

- *Intelligent well technology* that makes use of remote sensors, down-hole equipment and simulation models to determine the optimal drilling and production strategy for a given well. This could greatly reduce development costs, enhance well productivity and avoid the inflow of contaminants such as water (which would reduce processing costs).
- *Advanced fraccing techniques* such as novel well designs, simulation methods and the use of chemicals with high pressure to enhance the fracturing of low permeability formations to increase production.
- *Downhole compression* to maximise oil and gas recovery as reservoir pressure declines over time by installing a compressor at the bottom of the well, thereby increasing compression efficiency.
- *Subsea and Downhole Separation* of produced oil, gas and water using equipment installed either on the seabed, or in the producing well. This technology, together with technology that will allow the produced water and/or gas to be re-injected back into the reservoir, will increase oil production and reduce processing costs.

Although further cost reductions are to be expected, the rate of decline may slow over the next decade or so as the scope for technological advances and productivity gains are exhausted. Nevertheless, innovative technology

28. See Commission of the European Communities (1999) which estimates that world-wide oil and gas company R&D spending fell by an average 3% per year to under $3.5 billion over 1990-1997; and IEA (2000c), which shows a 31% drop in aggregate IEA government spending on oil and gas-related R&D (most of which is focused on upstream technology) to $284 million in 1998 compared to 1988.

may continue to open up new opportunities for exploiting resources that current technologies do not permit.

Unconventional Oil Supply Costs

The potential for future oil supply, and for ultimately recoverable resources from unconventional oil deposits, depends largely on production costs. The two principal sources of unconventional oil are located in Canada and Venezuela. Of the 2.5 trillion barrels of crude bitumen resources in place in Canada, about 12%, or 300 billion barrels, is thought to be ultimately recoverable, a figure comparable to the proven reserves of Saudi Arabia.[29] In Venezuela, over 1.2 trillion barrels of bitumen are thought to exist in the Orinoco belt, of which 270 billion barrels are thought to be economically recoverable with current technology.[30] In addition to bitumen, Canada and Venezuela have appreciable reserves of heavy oil.

Canadian Oil Sands

Supply costs cited by the Canadian National Energy Board include all costs associated with exploration, development and production. They include capital costs, operating costs, taxes, royalties and a 10 per cent real rate of return to the producer. The exploration costs associated with oil sands are minimal because the location and extent of the oil sands have already been well defined.

Between the early 1980s and the late 1990s, operating costs fell from $22 to $10 per barrel through continuous process improvements and recent major innovations in truck-and-shovel mining and hydro-transport. Industry analysts anticipate that further improvements in technology and operating methods may reduce operating costs (in money of the day) for integrated mining and upgrading units to $7 per barrel by 2004 and to $6 by 2015. Table 2.10 shows the current estimated supply costs for oil-sand operations in Canada.

The best indication of the increasing cost-competitiveness of Canadian unconventional oil sand production in the global oil market, and the expectation that this will continue in the future, is provided by current investment in future projects. Publicly announced development plans for the period 1996 to 2010 amount to nearly $25 billion, of which about $5 billion was spent to the second half of 2000. According to the Canadian

29. National Energy Board (2000a).
30. http://www.orimulsionfuel.com/origin/reserve/reserve.html

Table 2.10: **Canadian Oil Sands Approximate Production Costs**
($ per barrel)

Oil Sands in-situ	**Operating Cost**	**Supply cost**
Primary recovery - Wabasca	$2 to $5	$5 to $8
Primary recovery - Cold Lake	$5 to $7	$8 to $10
Cyclic steam stimulation	$5 to $8	$8 to $12
Steam assisted gravity drainage	$4 to $7	$6 to $11
Oil sands – mining		
Integrated mining/upgrading	$8 to $9	$11 to $14
Stand-alone upgraders	$8 to $9	$14 to $17
Mining - no upgrading	$4 to $6	$8 to $10

Source: National Energy Board (2000).

National Energy Board, production of synthetic crude and bitumen is projected to almost triple to about 1.7 mb/d by 2015, assuming a base case oil price of $18 per barrel (WTI).[31] This production could represent over half of Canada's projected production in 2015.

Venezuelan Orinoco Heavy Oil and Bitumen[32]

Operating costs for heavy oil from the Orinoco region are about $8 a barrel, including extraction and the costs of upgrading it into lighter oil at a refinery.[33] The actual operating cost of extracting the oil is not much different from that for conventional oil (about $3 in 2000[34]), but the oil is so heavy that it has to be upgraded to a higher quality so it is saleable.

Orinoco currently has a production capacity of 272 kb/d of heavy crude, or about 14% of the country's total production capacity. Capacity is to be increased to 630,000 b/d during the next three years, as production of light crude declines in maturing fields in western Venezuelan. The thick heavy oil from the Orinoco region must be diluted with lighter oil before it can be pumped through pipelines to the coast, where it is processed further.

31. National Energy Board (2000b).
32. Further discussion on unconventional oil in Venezuela is provided in the regional analysis section in this chapter.
33. *Bloomberg News*, 3 April 2001, Carlos Jorda, president of PDVSA subsidiary PDV America, presentation in New York.
34. *Bloomberg News*, 3 April 2001, Guaicaipuro Lameda, President of Petróleos de Venezuela S.A. (PDVSA), presentation in New York.

Heavy-oil projects are attractive because they incur a lower income tax rate. Heavy oil production is taxed at 34%, rather than the normal 62% incurred by traditional oil projects. All oil operations are subject to royalty payments of 16.67% of the value of their production.

Transportation Costs

The changing supply and demand picture will lead to greater global trade in oil. This will increase demand for oil transportation, either by tankers or pipelines.

Trends in transportation costs are less important for future oil supply than they are for gas. The costs of transporting oil by tanker are cyclical, and ship rates are set by supply and demand. The recent market for oil tankers has been firm, with relatively high spot rates for all classes of oil tanker. Tanker transportation costs are expected to fluctuate above mid-cycle levels in the near term due to three factors:

- Impending environmental regulation will accelerate the scrapping of older single-hull tankers.
- Increasing production from OPEC and non-OECD producers is expected to increase the demand for tankers.
- Pressure to increase investment returns.

Studies indicate that, for current new-building prices, a mid-cycle charter hire rate of $35,000 per ship per day is required for a Very Large Crude Carrier (VLCC) to generate an 11% return on capital employed.[35] Rates for VLCC tankers reached $100,000 per ship per day in 2000, a 10-year high, due primarily to significantly higher OPEC production. The range of transportation costs, the spot freight rate for transporting oil by tanker from the Gulf to North West Europe varied from 94 cents per barrel in June 1999 to $2.16 in June 2000 and was $1.50 per barrel in June 2001.[36]

The outlook for five-year charter rates, Table 2.11, shows that tanker transportation costs are expected to rise gradually to 2010 with progressively rising tanker demand.

Pipeline-transportation costs are heavy for oil supply from Russia, where oil can travel up to 4,000 km to export markets. It currently costs around $3 per barrel to transport Russian crude from Western Siberia to Black Sea terminals.[37] This cost is expected to fall in the future, due to

35. Lehman Brothers, 2001.
36. OPEC Market Indicators, Website, http://www.opec.org/NewsInfo/MarketIndicators/MI.asp
37. Oil Sector Research Report, *Troika Dialog*, May 2001.

Table 2.11: **Outlook for Five-Year Oil Tanker Time Charter Rates to 2010 by Ship Size** (thousands of dollars per ship per day)

	30,000 dwt	80,000 dwt	130,000 dwt	250,000 dwt
1995	15.75	20	22	30
1996	16	21	24	33
1997	16.25	21	26.25	36
1998	15	19	25	37
1999	13.50	16	21	29
2000	15.75	22	29.75	39
2001	17.50	25	34	45
2002	19	27	34	43
2005	16	23	28	36
2010	17.50	25	31	40

Note: Outlook for 1990s built vessel earning on the spot tanker market.
Dwt is dead weight tonnes. VLCC is a tanker of over 160,000 dwt.
Source: Petroleum Economics Limited (2000).

economies of scale and to improving cost control and efficiency at the monopoly oil pipeline company, Transneft.

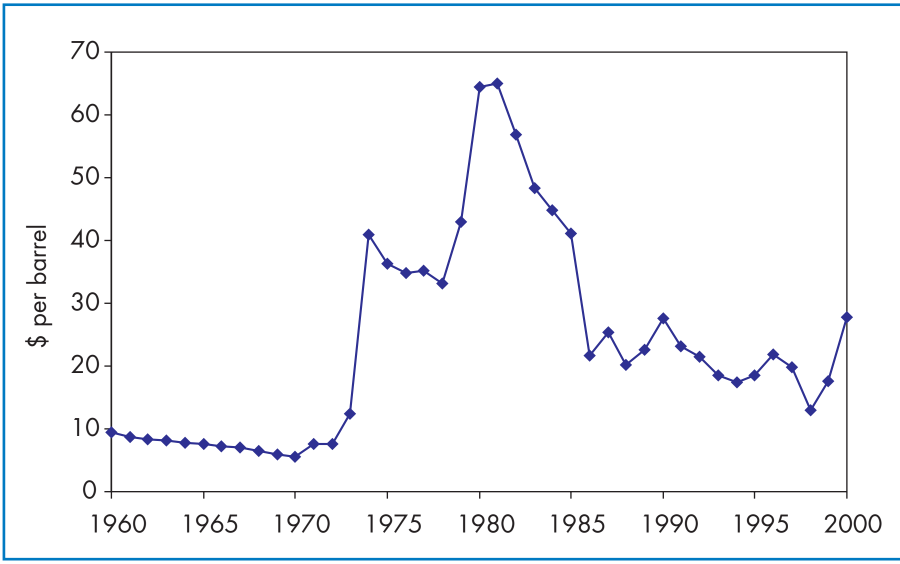
Prices

The oil price is an important determinant of oil supply. The development of additional oil production capacity to satisfy future demand is dependent both upon expectations of the price that can be obtained for the particular oil grade in the future and the supply cost estimate.

The price of a particular grade of crude oil is commonly based on a 'local marker price' such as West Texas Intermediate (WTI) or Brent. The analysis in this section uses the IEA average crude oil import price (cif) as the indicator of the "international oil price".

Given past trends in the evolution of the oil price (Figure 2.9), its behaviour over the next two decades is highly uncertain. The following analysis examines the potential effects of high and low oil prices on world supply and demand, using the World Energy Model. The reference year of 1997, used for supply and demand projections in the *WEO 2000*, is also used for this analysis.

Figure 2.9: **Historical Development of the IEA Crude Oil Import Price (cif)**



Source: IEA analysis.

Price formation

Oil price formation is complex. Prices fluctuate over time in line with shifts in current supply and demand as well as with market expectations of future supply developments. The production policies of a small number of OPEC and non-OPEC producing countries play a key role in determining production levels and influence the international market price of crude oil.

Several key demand factors affect price. Economic growth is the main determinant of worldwide demand. Perturbations in regional economic activity, like those in Asia in 1998, directly affect the world oil price. Major terrorist incidents, such as the attack on the World Trade Centre and the Pentagon, affect expectations of security of supply and can cause dramatic changes in the oil price. A more persistent, underlying characteristic of demand is the increasing requirement for lighter oil products for transportation. Such shifts in demand for specific products, changes in stocks and specific refinery input requirements and capacity also have an impact on the international crude oil price.

Price Sensitivity Analysis

Under the Reference Scenario price assumption in the *World Energy Outlook 2000*, global oil resources were not considered to be a constraint to satisfying expected growth in world oil demand to 2020. Political, economic and environmental factors were determined to be more important constraints to meeting the projections for oil demand and supply. The sensitivity analysis below examines the change in global oil supply and demand with future oil price assumptions above and below that of the Reference Scenario. The high and low oil price assumptions are only chosen to illustrate the potential effect that prices may have. Furthermore, oil prices rarely remain stable for long periods of time, with periods of high oil prices often followed by periods of low prices and vice versa. Assumptions relating to price volatility and price cycles can introduce uncertainty in the scenario analysis. Due to the relationship between oil and gas prices, the analysis also assumes that a lower or a higher oil price will result in a similar evolution of the gas price.

High Oil Price

In the high oil-price scenario, the average international oil price is assumed to increase from $20 in 1997 to $30 in 2002 and remains there in real terms until 2020. This assumption differs from the *WEO 2000* Reference Scenario, where the oil price is assumed to be $21 up to 2010 and then increase gradually to $28 by 2020.

There are several factors that might lead to a high oil-price scenario. One factor is the concentration of world oil production in a small number of OPEC countries. The share of world oil production in OPEC countries increased to over 40% in 2000, after falling from 54% in 1973 to 29% in 1985. This means that OPEC has the ability to influence the oil market, in the short term through production policies and in the long term through its decisions about expanding production capacity.

Much of the world's oil resources are not only controlled by a limited number of producers, they are also confined to a single region, the Middle East. This could potentially result in higher oil prices.

Low Oil Price

The low oil-price scenario assumes a decline in the world oil price. The average price falls from $20 in 1997 to $15 by 2002 and is assumed to remain there in real terms until 2020. This scenario is based on two possible premises: first, that advanced technologies in oil exploration and production reduce costs enough to offset rising pressure on the world oil price; and second, that there is no constraint on the development of production capacity in OPEC countries. OPEC production is estimated to be profitable at prices lower than $10 per barrel, so that even under this low-price assumption, OPEC countries increase earnings by increasing production.

Box 2.5: **Uncertainties Relating to Price Simulations**

The results of the alternative price projections are subject to uncertainty due to the following issues:

- *Size of the global resource base and the profitability of marginal reserves.* If reserves or undiscovered recoverable resources are greater or less than assumed, the results would be affected. The technological constraints facing unconventional-oil production could likewise limit the ability of unconventional oil to achieve its projected share in the high price case.
- *Economic feedback of oil price changes.* High oil prices reduce GDP in oil-importing countries, which in turn reduces the demand for oil. The lower demand eventually exerts downward pressure on the price. The effect of this economic feedback on oil demand and supply is not addressed in this exercise.
- *Changes in fiscal regimes.* Tax changes within a particular country and the interplay of tax policies between countries can affect world supply and thus the results. Tax regimes, however, are assumed to be unchanged over the projection period.
- *Investment returns on adding production.* Investment and supply costs, and the level of discount rate, will vary depending upon the source and type of oil supply.

Results of the Scenario Analysis

For both the high and low oil price scenarios, three separate effects resulting from the change in the international oil price are analysed: the change in oil demand by region, the adjustment in OPEC's share of world production and the consequences of oil price changes on OPEC revenue.[38]

38. For the sake of simplicity, OPEC revenue is defined as the product of OPEC oil production and the international oil price. This results in an over-estimate of OPEC revenue due to differences in the realised price of the oil produced compared with the international oil price, due to domestic consumption and different grades of crude.

Table 2.12: **Oil Price Assumptions and Impact on Supply and Demand for Three Price Scenarios, 1997 to 2020**

Price ($ per barrel)		**1997**	**2010**	**2020**
	High Price		30	30
World	*Reference*	*20*	*21*	*28*
	Low Price		15	15
Demand (mb/d)		**1997**	**2010**	**2020**
	High Price		44	47
OECD	*Reference*	*42*	*48*	*51*
	Low Price		53	57
	High Price		42	59
Non-OECD	*Reference*	*33*	*48*	*64*
	Low Price		50	67
World Oil Balance (mb/d)		**1997**	**2010**	**2020**
	High Price		86	106
World	*Reference*	*75*	*96*	*115*
	Low Price		103	124
Supply (mb/d)		**1997**	**2010**	**2020**
	High Price		29	46
OPEC	*Reference*	*30*	*44*	*62*
	Low Price		54	74
	High Price		57	60
Non-OPEC	*Reference*	*45*	*52*	*53*
	Low Price		49	50

Note: Demand and supply have been adjusted for bunker and stock changes and processing gains. Non-OPEC oil supply includes unconventional oil.

High Oil Price Scenario

The results in Table 2.12 show that world demand in 2020 would be 7% lower in the high oil-price scenario than in the Reference Scenario. A higher oil-price discourages consumption, favours conservation of energy and encourages consumers to switch to other fuels, resulting in a drop in oil's share in the energy mix. The magnitude of the effect differs among regions analysed in the World Energy Model. Despite the higher oil price, demand will continue to increase through to 2020.

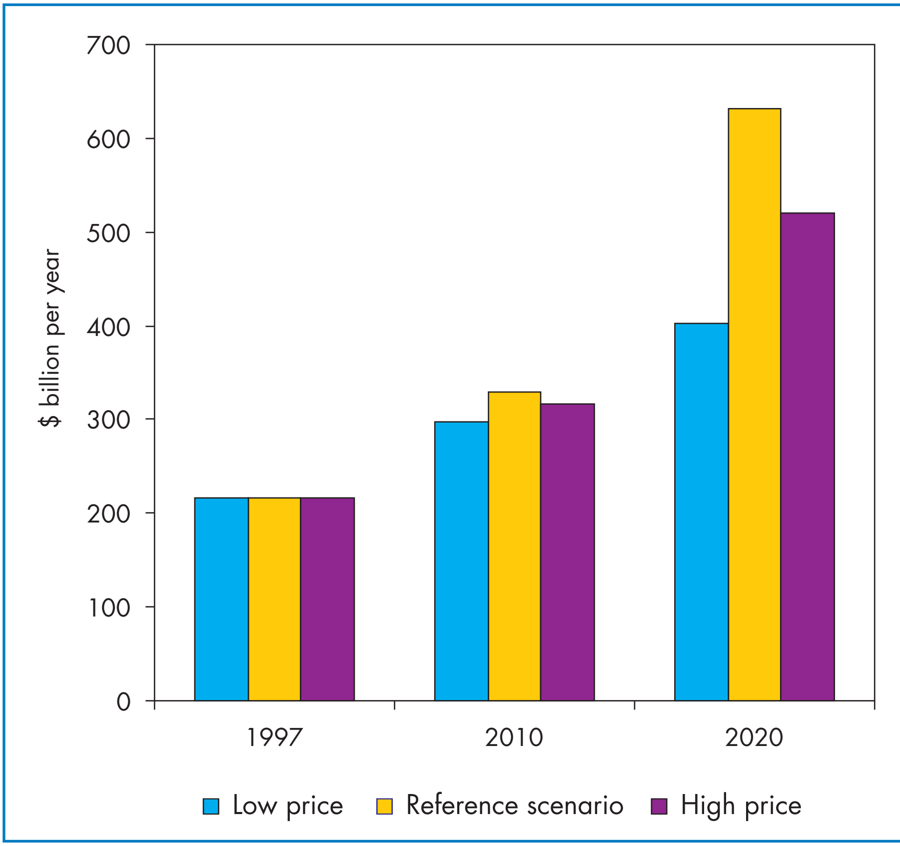
The decrease in world oil demand due to the higher price leads to lower world production, the impact of which again varies by region. OPEC's production in 2020 declines by 24% compared with the reference scenario. This is the result of several factors. First, high oil prices stimulate substantial increases in production of unconventional oil. In cumulative terms, unconventional production would be about 50% higher under high oil prices compared with the Reference Scenario. The share of unconventional oil production in total world oil supply rises from 1.7% in 1997 to 6% in 2020, compared with 3.7% in 2020 in the Reference Scenario. Second, OPEC production would face increasing competition from conventional oil production in non-OPEC regions. Such production would be nearly 7 mb/d higher in the high oil-price scenario in 2020, despite lower global demand. Finally, a higher international oil price would encourage the development of additional reserves, and ultimately lead to higher non-OPEC production, through several effects:

- An increase in recoverable resources: oil that is marginally unrecoverable because of high costs could become economic with higher oil prices. In 2020, resources are 20% higher in the high-price case and 6% lower in the low-price case, compared with the Reference Scenario.
- An increase in investment in exploration and production activities enhances the likelihood of new discoveries.
- An upsurge in R&D investments could result in technological improvement in drilling and recovery.

As a result of lower oil demand and higher non-OPEC supply in the high-price scenario, OPEC's share of world oil supply increases at a slower rate than otherwise, reaching 44% in 2020, compared with 54% in the Reference Scenario. Nevertheless, OPEC's annual revenues would be equivalent for both scenarios in 2010 (Figure 2.10). After 2010, however, OPEC's high price revenues are lower than in the reference case – as the loss in production is no longer compensated by the high price. In 2020, OPEC's annual revenue is expected to be about $110 billion less than in the Reference Scenario.[39] This supports the conclusion that, while a higher price may be profitable for exporting countries in the short-term, it may yield lower revenues in the longer term.[40]

39. Applying a discount rate of 10% to cumulative OPEC revenues over the period 1997-2020 also yields higher revenues in the Reference Scenario than in the high price scenario.
40. This result is in line with findings of the OPEC (2000).

Figure 2.10: **OPEC Annual Oil Revenues for the Three Price Scenarios**



Source: IEA analysis

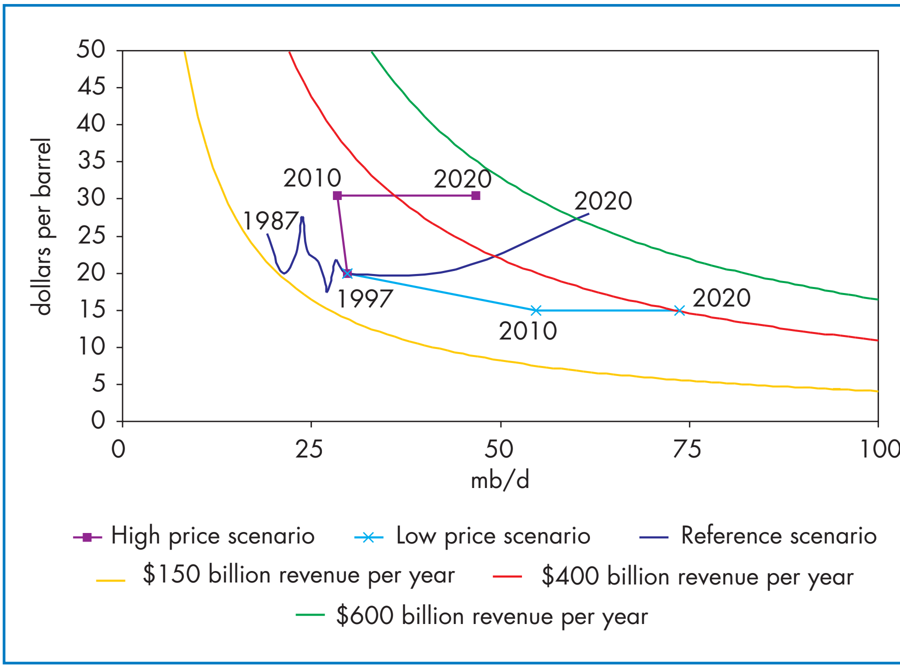
Low Oil Price Scenario

World oil demand would be 8% higher in the low oil-price scenario than in the Reference Scenario. Low oil prices encourage consumption, discourage conservation and favour the use of oil over other fuels. Again, the effects of a lower international oil price differ among regions. Developing Asia experiences the largest increase in demand. The impact in the net exporting regions, such as the Middle East and oil-exporting African and Latin American countries, is much lower.

To satisfy the rapid growth in oil demand in the low-price scenario, OPEC production would rise dramatically. In 2020, OPEC's share of world oil supply would be 59% in the low oil-price scenario compared with 54% in the Reference Scenario. The rise in OPEC production would be necessary to offset production declines in parts of the rest of the world. Non-OPEC production in 2020 would be 5% lower in the low oil-price scenario. In 2020, global unconventional oil production would be 21% lower terms in the low-price scenario compared with the Reference Scenario.

Despite lower oil prices, OPEC revenue would still increase over the projection period, as the growth in production would more than compensate for the price decline. OPEC revenue would, however, increase at a slower rate in the low-price scenario than in the Reference Scenario.

Figure 2.11: **Oil Price, OPEC Production and Revenues for the Three Price Scenarios**



Note: The revenue curves indicate the combinations of price and production that yield constant revenues.
Source: IEA analysis.

Supply and demand in the world oil market vary significantly with prices. World oil demand is expected to rise significantly even under the high-price assumptions. In *all* the scenarios, the OPEC producers continue to dominate world supply.

Given the world's expected dependence upon OPEC oil production, investment in capacity expansion in the region is crucial. Higher oil prices encourage investment in capacity but eventually dampen oil demand, and thus OPEC production.

Although high oil prices affect demand in all oil-importing countries, the impact on oil demand in developing countries is greater than elsewhere. An increase in the oil import bill in these countries can lead to a destabilising deterioration in the trade balance and can feed inflation. The fact that oil demand has been increasing rapidly in the developing world exacerbates the problem. While these macroeconomic effects are not analysed in detail here, the effects of varying oil price assumptions give an indication of its considerable influence on demand and supply.

In all the price scenarios, annual oil revenues to OPEC countries increase. The analysis suggests that a high oil price will not yield maximum revenues for OPEC countries in the long term. (Figure 2.11)

Investment

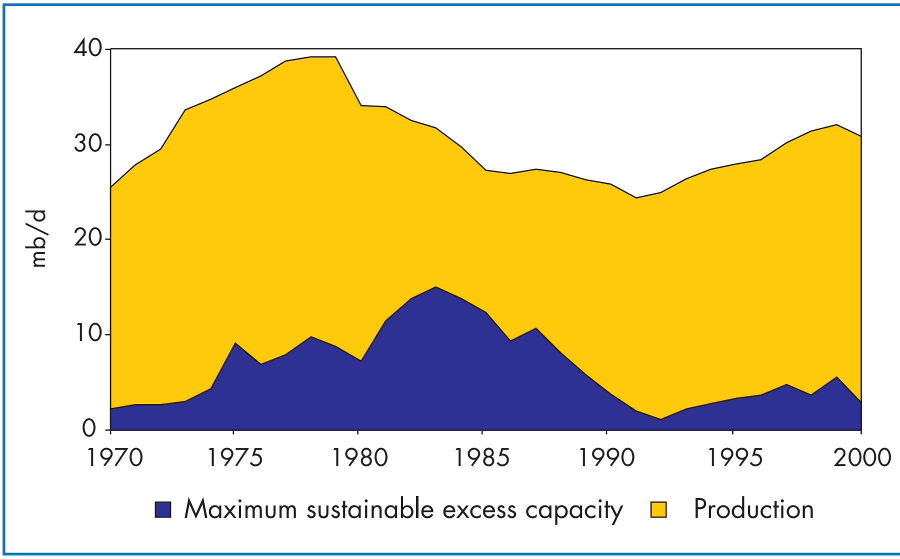
Increasing oil production to meet projected growth in demand will require a tremendous amount of investment. The price of oil and its associated volatility will play a key role in determining how much capital is invested in building production capacity. Attracting future capital will cost more in a volatile price environment than in a stable price environment. The higher cost of capital could tend to choke off investment, which may further exacerbate volatility.

The availability of surplus production capacity can help to mitigate price volatility, as well as ensure consumers of a secure oil supply in the event of supply disruptions or unexpected changes in demand. In modelling the oil market,[41] it is assumed that OPEC production fills the gap between non-OPEC production and total oil demand. This variable call on OPEC supply has led to excess OPEC production capacity as indicated in Figure 2.12.

During the next 20 years, considerable investment will be needed to add new production capacity both to replace production lost through natural decline in ageing production areas, as well as increase supply in line with demand growth.[42]

41. IEA (2000b).
42. The Reference Scenario projections of *WEO 2000* show that oil demand is projected to grow at an average annual rate of 1.9% from 1997 to 2020.

Figure 2.12: **OPEC Maximum Sustainable Excess Crude Oil Production Capacity and Production, 1970 to 2000**



Source: OPEC Secretariat.

The relationship between resource depletion and production decline is discussed in Box 2.6. There is rarely a case where no investment occurs to sustain production, hence, the "cashless" decline in production cannot be directly observed. However, some analysts believe that cashless decline rates for oil production in many regions exceed 10% per year.[43] This rate may increase as older giant oil fields are no longer able to sustain plateau production and new fields exhibit fast decline rates once they pass peak production due to more efficient oil extraction technology.

The decline rate is a critical determinant of investment in the oil industry. To illustrate the effect that natural decline rates can have on future production and investment, a natural decline rate of only 5% per year is assumed. Using this rate and a growth in demand of 1.9% per year, the additional production capacity that needs to be brought on stream by 2010 is 61 mb/d (Figure 2.13). The investment required to develop this production capacity at a cost of $5 billion per 1 mb/d[44] in major Middle

43. See, for example, EIA (2000a); *Journal of Petroleum Technology* (2001); *Oil and Gas Journal* (2001); Simmons (2000); among others.
44. Prince Faisal Bin Turki Bin Abdul Aziz Al-Sa'ud speech, The Development of Middle East Energy conference, London 12th February, 2001

Box 2.6: **Resource Depletion and Production Decline**

Depletion, and rate of depletion, and decline, and rate of decline, have separate and precise meanings.

"Depletion" of a reservoir refers to the decrease in the amount of oil contained in the reservoir. For example, if a reservoir is judged to have 100 million barrels of oil remaining on 1/1/1999 and, following production, has only 90 million barrels remaining on 1/1/2000, the depletion has been 10 million barrels, and the depletion rate is 10 million barrels per year, or 10% per year.

"Decline" of a reservoir refers to the decrease in the rate of oil production in the reservoir. For example, if a reservoir produces 100 barrels per day (b/d) of oil on 1/1/1999 and, following production, produces only 95 b/d on 1/1/2000, the decline is 5 b/d, and the decline rate is 5 b/d per year or 5% per year.

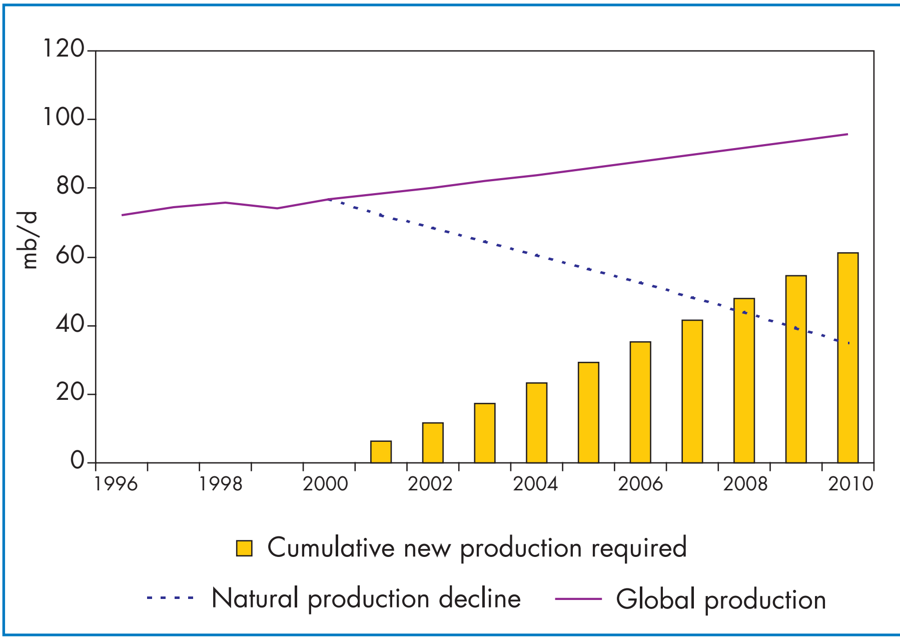
Depletion and production decline are strongly influenced by advances in technology. Development and deployment of technology has allowed oil to be produced from areas that were previously uneconomic, and has increased the amount of oil that can be economically recovered from existing fields. This has led to an increase in resources and can help offset decline. However, technology also allows the resource base to be depleted more quickly, increasing the rate of production decline following peak production.

To examine the impact of decline on production and investment, a distinction is made between the observed decline rate and the "natural" or "cashless" decline rate. The "cashless" decline rate is the decline in production that would be observed in the absence of additional investment to sustain production. Examples of investment to sustain production include additional drilling and enhanced secondary and tertiary recovery techniques.

East OPEC countries would be over $300 billion in today's money. The average investment required to add production capacity in non-OPEC countries is estimated to be four times higher, representing a capital requirement of over $1 trillion. This basic analysis indicates the enormous capital requirements to replace production lost due to decline as well as to satisfy growth in demand to 2010.[45]

45. The issue of investment to meet global energy supply will be analysed in detail in the IEA's World Energy Outlook Insights publication planned for 2003.

Figure 2.13: **Impact of Decline Rate on Production**



Source: IEA analysis.

Investment Trends

A recent survey of exploration-and-production (E&P) spending shows the considerable amount of capital allocated to production and exploration in the oil and gas industry. E&P spending for the 274 oil and gas companies surveyed, is expected to increase from $92 billion in 2000 to $115 billion in 2001 (Table 2.13). This 25% growth in spending is the largest year-over-year growth since 1981. Of this total increase, companies project a 19% increase in North American spending for 2001, after a strong 40% increase in 2000. Outside North America, spending is expected to grow 20% after a moderate 8% increase in 2000. Small independent US companies are the most responsive to changes in the short-term economics of the E&P industry, showing the largest percentage changes in spending activity.

The increase in spending reflects increases in oil and natural gas prices that have exceeded the expectations of many of the companies, resulting in much higher cash flows than anticipated. Due to these strong results, as well as to heightened confidence in OPEC's ability to maintain oil prices within their stated range of $22 to $28/bbl (based on an OPEC basket of

Table 2.13: **Planned 2001 Exploration and Production Expenditures, June 2001 vs. December 2000** (million $)

	Responses	2000	2001*	% Change
	June 2001 Survey			
U.S. Independents	177	$15,010	$19,623	31%
U.S. Majors	11	$12,113	$13,560	12%
U.S. Total	188	$27,123	$33,183	22%
Canada	92	$10,537	$12,852	22%
Outside North America	101	$53,846	$68,645	28%
Worldwide	274	$91,507	$114,680	25%
	December 2000 Survey			
	Responses	2000*	2001*	% Change
U.S. Independents	154	$14,064	$16,926	20%
U.S. Majors	11	$10,852	$12,794	18%
U.S. Total	165	$24,916	$29,720	19%
Canada	77	$11,012	$13,084	19%
Outside North America	89	$58,870	$70,690	20%
Worldwide	234	$94,798	$113,494	20%

* Estimated.
Source: Salomon Smith Barney (2001).

crude oils), companies have increased their E&P budgets. The largest increases are outside North America. However, U.S. and Canadian spending plans have also risen strongly, driven by record-high natural gas prices and an improving long-term outlook. Reflecting this increase in spending, North American rigs in operation recently rose to their highest levels since 1985, while international rigs operating are 9% below 1997's peak levels and 40% below 1985.

The rapid growth in activity has led to an increase in oilfield service prices, estimated at 15%–20% from 1999 to 2000.[46] This has also affected E&P spending plans. North American activity would have been higher if prices, particularly drilling rig day rates, had not risen so sharply. With such a fast rate of increase in work programmes, certain equipment and services, such as jack-up rigs and pressure-pumping services reach full

46. Salomon Smith Barney (2001).

utilisation, effectively capping short-term activity. Part of the increase in spending is inevitably related to higher oilfield service prices.

The ability of the oil and gas industry to respond to increases in prices, and the consequent increase in E&P spending is limited by the availability of specialised oilfield service equipment and qualified personnel. Volatile prices complicate the investment planning of oilfield service companies and inevitably lead to conservative spending and consequent limitations on capacity. In a survey conducted in December 2000, 83% of oil and gas companies indicated concern about the availability of oil services during 2001, particularly drilling rigs and field personnel.[47] This is the highest per centage in the 11 years that companies have been asked this question.

In response to the investment challenges, the oil industry is making greater use of information networks to improve productivity and quality of service. Training programs are conducted over networks to instruct people in their work places in the remote areas where oil is often located, onshore or offshore. IT and e-commerce can give companies commercial access to outside experts, wherever they may be physically located, on a payment-by-performance basis. One recent example is an initiative that gives oil companies access to expert earth scientists for picking well locations in the oil exploration and development process.[48] If the time for picking prospects can be reduced, then companies can increase drilling and production. This can help to defer field abandonment costs, combat steep production decline rates, reduce operating costs and increase the return on capital invested in platforms and infrastructure. Companies often lack the in-house staff to analyse in detail all the areas licensed by the company. It can also be more productive to use IT to access a pool of geographically-dispersed experts on a reliable, commercial basis.

The oil and gas industry is currently enjoying strong profitability due to improvements in productivity, cost reductions and strong oil and gas prices. Due to volatility and uncertainty, however, companies are conservative in their price expectations, assuming prices that are substantially below current levels.

47. Schroder Salomon Smith Barney (2000).

48. A recent initiative, known as Virtual Prospect, employs a combination of IT and e-commerce to enhance the productivity of oil-and-gas-company prospect analysis. Association of American Petroleum Geologists, Explorer article, June 2001, http://www.aapg.org/explorer/archives/06_01/prospects.html

Government Policy and Industry Developments

Oilfield exploration, development and production economics are influenced, directly and indirectly, by government policies. These policies affect operating costs and investment returns from oil production. Government policy also considers long-term energy security and import dependency, environmental issues and may involve the determination of production levels. The main areas of government activity in the oil industry are similar to those for gas, namely:

- upstream taxation and the investment environment;
- environmental regulations;
- state ownership of productions assets;
- initiatives to improve supply security;
- transit policies.

Government activity and developments in the industry environment are considered below. Transit policies are discussed in Chapter 3.

Upstream Taxation and the Investment Environment

The fiscal regime for upstream activities has a major impact on actual and expected returns from investment in the exploration and development of oil reserves. The effect of upstream taxation on future oil supply is particularly significant in the case of countries with large oil reserves, such as Russia and certain OPEC countries, including Saudi Arabia, Iran and Iraq. The implementation of an appropriate tax code in Russia would have a major impact on reducing the uncertainty of future investment returns and stimulating the development of oil production capacity in Russia.

Investors need a national legal regime that meets basic criteria for reduced political risk. Risks to be avoided include unilateral changes in legislation, termination of licenses by the government or unexpected changes in the fiscal regime. In some countries, there is additional risk associated with export rights and dispute resolution.

Experience in many countries has shown that investors regard Production Sharing Agreements (PSAs) as a useful mechanism on which to base major investments especially while an overall tax regime is being drafted and put into place. The recent boom in investment in Azerbaijan shows how PSAs can attract investment, especially when they are underpinned by strong treaty obligations. Azerbaijan was among the first countries to ratify the Energy Charter Treaty (ECT). It has signed PSAs for total investment of over $30 billion. Similarly, the determination of national taxation or production-sharing terms in the Caspian region, West

Africa and in parts of Latin America is leading to significant investment in oil production, by both local and international oil companies.

Upstream investment in mature areas such as North America and the North Sea can also be encouraged through the adjustment of fiscal regimes, combined with other government policies aimed at improving commercial returns on oil supply, such as the encouragement of Research and Development in upstream technology. Governments are increasingly working with industry to improve the overall investment climate, as well as reduce oil import dependency and provide employment.

Box 2.7: **UK Government and Industry Initiatives**

In response to low oil prices in late 1998, the UK Government and the oil industry set up an Oil and Gas Industry Task Force (OGITF) to reduce the cost-base of activity on the UK Continental Shelf. Work groups were established to act in the key areas identified by the industry: vision, competitiveness, fiscal, regulation and licensing, skills and training, innovation and technology, and sustainable development. The task force identified a vision for the UK Continental Shelf involving the following goals for 2010:

- production of 3 million boe per day;
- sustaining investment at £3 billion per year;
- finding ways of supporting up to 100,000 jobs more than there would otherwise have been;
- prolonging UK self-sufficiency in oil and gas.

PILOT was established in January 2000 to implement the OGITF vision. PILOT consists of members from Government departments and industry representatives. Focus areas of PILOT work groups include:

- regulation and licensing, addressing issues connected to the UKCS regulatory regime;
- an Economic Advisory Group (EAG), assessing the industry's exploration and production investments;
- undeveloped discoveries, examining methods to accelerate UKCS developments (www.logic-oil.com/projects/accelerator.html).

Following OGITF, other independent organisations have been established:

- Leading Oil and Gas Industry Competitiveness (LOGIC) to promote best practice throughout the oil and gas supply chain (www.logic-oil.com).
- Industry Technology Facilitator (ITF), to improve the facilitation and flow of new oil and gas technology to market (www.oil-itf.com).
- Licence Initiative for Trading (LIFT) - a new website to promote oil and gas licence trading (www.uklift.co.uk).
- Digital Energy Atlas and Library (DEAL) – an interactive map providing an index for UKCS oil and gas data (www.ukdeal.co.uk).

Environmental and Land-use Regulations

Environmental and land-use policies and regulations place constraints on upstream and transportation activities. They often increase the cost of exploration, development and production. There are many examples of problems faced in the development of oil reserves in areas of outstanding natural beauty and in areas of high population density. One of the best examples is the 1002 area of the Alaska National Wildlife Reserve (ANWR) in the United States. This area, covering 1.5 million acres of the 19 million-acre ANWR, is estimated to hold 10.3 billion barrels of oil.[49] This compares with total US proven reserves of 32 billion barrels (Table 2.6). The USGS has projected that ANWR peak production rates could range from 1 to 1.35 mb/d. Production could begin around 2010, and peak production would come 20-30 years after that.[50] This would be equivalent to more than 20% of current US production.

The U.S. National Energy Report points to improvements in exploration and development technology that have dramatically reduced the surface area required to gain access to underground oil reservoirs.[51] This technology includes the use of ice roads and drilling pads, low-impact exploration approaches, such as winter-only activity, and extended reach

49. USGS (1999).
50. EIA (2000b).
51. US National Energy Policy Development Group (2001).

and through-tubing rotary drilling. The report estimates that only 2,000 acres will be disturbed if the 1002 Area is developed.

State Owned Oil Production

The involvement of governments in oil production has changed considerably in the last three decades. Direct state-ownership of oil production increased in the 1970s, with the nationalisation of oil-company assets in many OPEC countries. The 1980s and 1990s saw the opposite trend in many countries, with the privatisation of wholly or partly state-owned oil and gas companies. This development, together with industry consolidation and increased competition, has led to improvements in productivity and a reduction in costs. This trend is expected to continue. In addition, the growing involvement of publicly traded international oil companies in exploration and production in several OPEC countries could also enhance production prospects. Table 2.14 shows the top 20 largest producing companies in 2000 compared with the top 20 in 1972.

Industry Developments

The ownership of oil producing assets has changed considerably with time. Oil companies have had assets nationalised, like BP and Total; have merged with other companies, like Exxon/Mobil, BP/Amoco/Arco and Total/PetroFina/Elf Aquitaine; or have returned wholly or largely to the private sector through privatisation, like BP, TotalFinaElf, Petrobras and ENI. Mergers and acquisitions (M&A) have been supported by shareholders as they have reduced costs (Figure 2.14) and improved returns on investment. They have increased shareholder value through economies of scale and scope, and expanded access to international markets. Consolidation has also occurred among oilfield service companies, reducing duplication, and enabling synergies between operating groups that reduce costs and improve quality and productivity. Governments have a key role to play in encouraging competitive energy markets, by establishing appropriate regulatory frameworks and monitoring the competition effects of mergers.

Privatisation of national oil companies has improved market transparency through greater corporate communication and the adoption of uniform reporting standards for production, reserves estimation and financial results. Capital efficiency and returns on investment have been enhanced due to greater company accountability and competition for capital. This trend is expected to continue to boost production

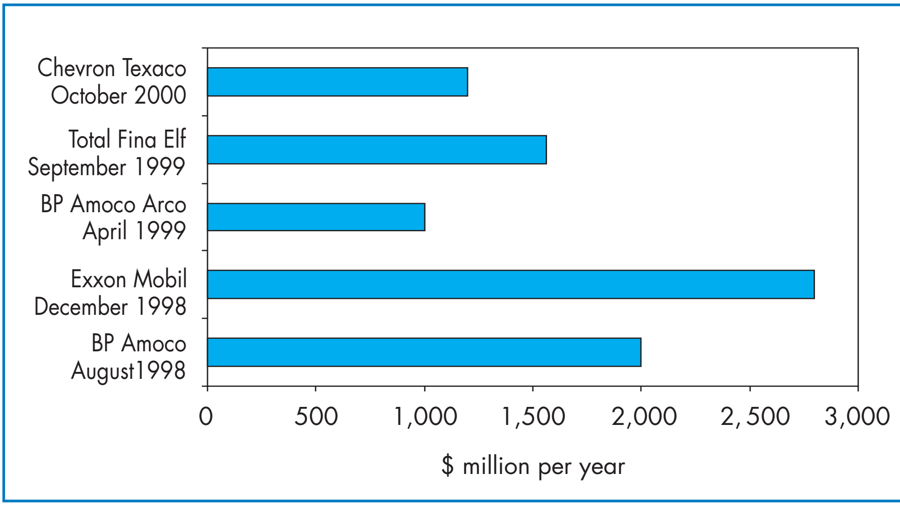
Table 2.14: **Largest Oil-Producing Companies Ranked by Estimated Oil Production** (mb/d)

	1972			2000		
Rank	*Company*	*Production*	*Share*	*Company*	*Production*	*Share*
1	Exxon	5.0	10.8%	**Saudi Aramco**	8.8	11.7%
2	**BP**	4.7	10.1%	**NIOC (Iran)**	3.8	5.0%
3	Shell	4.2	9.0%	**PEMEX (Mexico)**	3.5	4.6%
4	Texaco	3.8	8.2%	**PDVSA (Venezuela)**	2.9	3.9%
5	Chevron	3.2	7.0%	**INOC (Iraq)**	2.6	3.4%
6	Gulf	3.2	7.0%	ExxonMobil	2.6	3.4%
7	Mobil	2.3	5.0%	Shell	2.3	3.0%
8	**Former Planned Economies**	1.3	2.8%	**CNPC (China)**	2.1	2.8%
9	**CFP (Total)**	1.0	2.1%	BP	1.9	2.6%
10	**Sonatrach (Algeria)**	0.9	2.0%	**KPC (Kuwait)**	1.9	2.5%
11	Amoco	0.8	1.8%	**ADNOC (Abu Dhabi)**	1.8	2.4%
12	Arco	0.7	1.4%	Lukoil	1.5	2.1%
13	Du Pont	0.6	1.3%	**NOC (Libya)**	1.5	2.0%
14	USX (Marathon)	0.5	1.0%	TotalFinaElf	1.4	1.9%
15	**PEMEX (Mexico)**	0.4	1.0%	**Petrobras**	1.3	1.8%
16	Occidental	0.4	1.0%	**Pertamina (Indonesia)**	1.2	1.6%
17	Getty	0.4	1.0%	**NNPC (Nigeria)**	1.2	1.6%
18	Sun	0.4	0.8%	Chevron	1.2	1.5%
19	Unocal	0.4	0.8%	**Sonatrach (Algeria)**	1.0	1.3%
20	Phillips	0.3	0.7%	Yukos	1.0	1.3%

Note: Companies with state participation are in bold.
Estimates of company production may vary depending on reporting standards, allocation of production, consistency of definitions and availability of accurate data.
Source: Company reports, EIA *Petroleum 1996, Issues and Trends*, IEA analysis.

performance and reduce costs, leading to increased investment in oil production capacity.

Figure 2.14: **Annual Cost Savings from Mergers and Acquisitions**



Note: Cost savings are those announced at the time of the merger.
Source: Company reports and press announcements.

Security of Supply Initiatives

The Reference Scenario projections for oil demand and production in the *WEO 2000* imply a significant increase in international trade to meet a widening gap between consumption and indigenous output in many parts of the world. The security of supply concerns raised by this projected trend have prompted the governments of oil-importing countries and regional groupings to develop new policies.[52] Key objectives include the following:

- strengthening of systems for collecting and analysing oil-market information (construction of an energy security information network);
- improvement of the transparency and the integrity of information in the oil market; [53]
- diversification of energy sources;
- strengthening of relationships with major oil-producing countries.

52. See recent reports written by the regions with high and increasing dependency highlight policy issues including: APERC (2000), Oak Ridge National Laboratory (2000), EC (2000), Wu (2001).
53. The IEA is working with other organisations on a global initiative to improve the transparency and integrity of energy data.

The International Energy Forum (IEF) was created to encourage dialogue between producing and consuming countries, with the aim of building confidence, exchanging information and developing a better understanding of the underlying energy issues affecting the world. The objective of the Seventh IEF, hosted by Saudi Arabia in November 2000, was to advance the dialogue between oil and gas producers and consumers in the interest of stable and transparent energy markets, sustainable development and a healthy world economy.[54] In another example, the European Union has launched an ongoing dialogue with the Russian Federation about diversification of oil supply.

The 26 Member countries of the IEA are committed to taking joint measures to address their energy security concerns and to deal with oil supply emergencies. These measures include sharing energy information, co-ordination of energy policies and co-operation in the development of rational energy programmes.

Regional Analysis

The country analysis covers major non-OECD producers and Mexico. There is considerable published analysis available on the oil production outlook in major OECD producing regions, such as OECD North America and OECD Europe. Some of the key features of the outlook for production in these regions have been discussed in the preceding section.

Russia

Overview

The Russian oil sector contributed an estimated 8% of Russia's GDP and 35% of foreign-trade earnings in 2000. In recent years it has also supplied approximately 25% of Federal budget revenues.

The Russian oil industry was transformed in the 1990s. Reorganisation began in 1992-1993 with the establishment of three vertically integrated companies (VICs), Lukoil, NK Surgutneftegaz and Yukos, each combining exploration, production, refining, distribution and retailing. In mid-2000, the State Statistical Bureau, Goskomstat, identified a total of 132 enterprises producing oil in Russia. But only twelve of these

54. www.energyforum.gov.sa/html/objects.html.

(eleven VICs and Gazprom) produce more than 200 kb/d. The eleven large VICs, collectively accounted for 88% of national crude oil production and 79% of refinery throughput in 2000.

Increased transparency and the development of competition between oil companies, together with the creation of an effective legal and regulatory environment, are essential to achieving growth in Russian oil-industry investment and production. Pressure from shareholders on the issues of corporate practice, shareholder rights and transparency has forced Russian oil companies to make concessions. They have improved their communications with stakeholders. They now prepare financial accounts to international standards and provide international audits of oil and gas reserves. But much remains to be done.

Key oil policy-issues include:

- establishment of a stable and effective tax code;
- relaxation of administrative restrictions on exports and improved access to export pipelines;
- completion of the privatisation of state oil assets;
- publication of official data on Russian reserves; more transparent and reliable data would increase consumer and investor confidence in the Russian petroleum sector;
- elimination of price distortions in the domestic oil-product market;
- completion of the Production Sharing Agreement regime to improve the investment climate in the upstream oil sector.

Development of the Russian oil sector requires large investments to expand production capacity and build the necessary transportation infrastructure. Improved understanding of the Russian supply outlook will help in the development of export markets. The European Union and China have already shown a keen interest in receiving reliable supplies of Russian oil.[55] Russia shares land borders with both the EU and China and also has oil fields located close to Japan.

Resources, Production and Exports

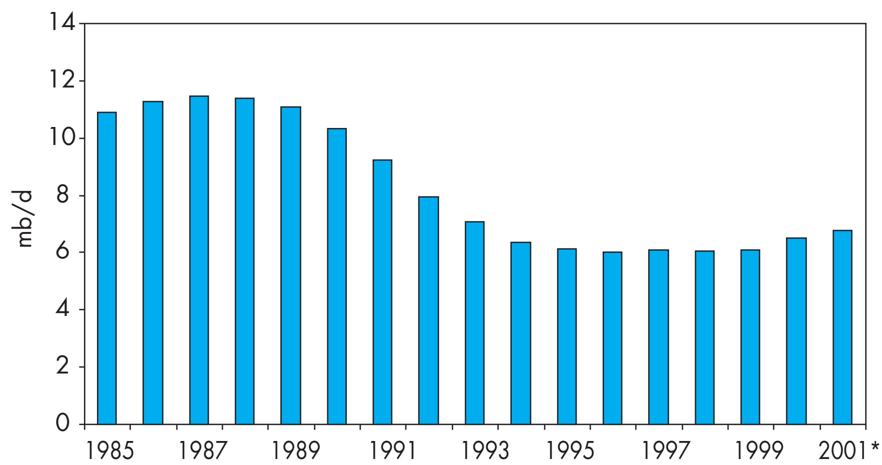
Resources

After Saudi Arabia, Russia has the world's second-largest oil and natural gas liquids reserves at around 137 billion barrels according to estimates by the US Geological Survey (USGS).[56] The sum of Russian

55. EC (2000).
56. USGS (2000).

cumulative production and remaining oil reserves, 235 billion barrels, is not much larger than that of the United States (203 billion barrels). By 1996, Russia had produced only 97.5 billion barrels of its oil reserves compared with 171 billion barrels for the United States. IHS Energy estimates remaining Russian reserves were 140 billion barrels at the end of 2000.[57] Official Russian figures are not published, but analysis of statements made by government officials suggests there are oil reserves in the range of 143 to 147 billion barrels. The USGS estimates mean undiscovered recoverable resources in Russia at 77 billion barrels of oil, and 40 billion barrels of NGL.

Figure 2.15: **Russian Oil Production, 1985-2001**



*The IEA estimates production of 6.9 mb/d in 2001.
Source: IEA and Russian Ministry of Energy (2000a).

Production

Russia was the world's largest oil producer in the late 1980's, with production peaking at 11.4 mb/d in 1987. That figure declined by over 47% during the next 9 years, reaching a low of 6.0 mb/d in 1996. (Figure 2.18) Production stabilised for the remainder of the 1990s yet showed significant growth of 5.7% in 2000 as a result of higher investment and improved technology. Russia's production of 6.5 mb/d in 2000 ranks third behind Saudi Arabia and the United States.[58]

57. IHS Energy Petroleum Economics and Policy Solutions database
58. IEA *Oil Market Report.*

A major underlying cause for the upturn in oil production, beginning in 1999, was the rebound in international oil prices that occurred after March of that year. Many Russian oil companies used the period of lower oil prices to streamline their costs and drop unproductive operations. The four-fold rouble devaluation after the August 1998 financial crisis also improved Russia's upstream economics. With 90% of Russian oil company spending denominated in roubles, the devaluation brought a dramatic decrease in costs and an increase in the purchasing power of dollars. Companies such as Lukoil saw their production costs drop from \$7.50 per barrel in 1997 to \$2.50 per barrel[59] after the August 1998 crisis. Lukoil's production costs in Western Siberia are expected to grow from \$4.6 per barrel in 2000 to \$5.7 per barrel in the period 2005 to 2010.[60]

Export Capacity

Due to the precipitous decline in Russia's crude oil production and demand in the early 1990s, total flows in the Russian oil pipeline system are now much smaller than before. Shipments declined by 43% between 1990 and 1996, from 10 mb/d to 5.7 mb/d. Nevertheless, bottlenecks still exist in Russia's oil pipeline system (Figure 2.16). Difficulties are apparent at the main export ports and along the pipelines supplying them, particularly at Novorossiysk, Russia's major oil Black Sea export port. In the past, a large portion of Russian total crude-oil flow was dispersed to refineries across the former USSR, and a substantial amount was delivered to Eastern Europe via the Druzhba Pipeline. With the dramatic decline in oil demand in the former Soviet republics and in Eastern Europe, a much larger proportion of the total flow now goes to the small number of export ports dispatching crude to other international markets. Since the FSU pipeline system was designed mainly to move crude to internal consuming centres, much of the core system in the Russian interior now has redundant capacity.

For the most part, decisions relating to which market and export route is used are made by determining overall export access rather than by producers. With more effective competition among routes, the differentials between these may be reduced.

59. This did not include VAT and Excise taxes, which would add about \$1 per barrel to costs.
60. Russia Market Daily, *Troika Dialog*, Moscow, 10 July, 2001

Figure 2.16: **Russia's Main Oil Export Routes**

Source: IEA analysis.

Outlook for Oil Production and Exports

Production

Russia's official energy outlook, *Energy Outlook: Main Provisions to 2020*, projects a 0.5% average annual growth rate in oil production, with oil output reaching 6.7 mb/d in 2010 and 7.2 mb/d in 2020.[61] *WEO 2000* projects Russian oil production to rise to 7.1 mb/d by 2010 and to 7.9 mb/d by 2020, with an average annual production increase of about 1.1%. In view of its strong output performance in 2000/2001 and the country's improving regulatory environment, Russia could well exceed the *WEO 2000* production projections. Russian industry projections are much higher than those of the government.[62]

Average daily production per well has fallen to about a quarter of what it was in the mid-1970s (Figure 2.17). However, the considerable stock of wells already drilled, the existing infrastructure and the large amount of proven reserves may offer significant opportunities to increase production from existing wells at modest cost.

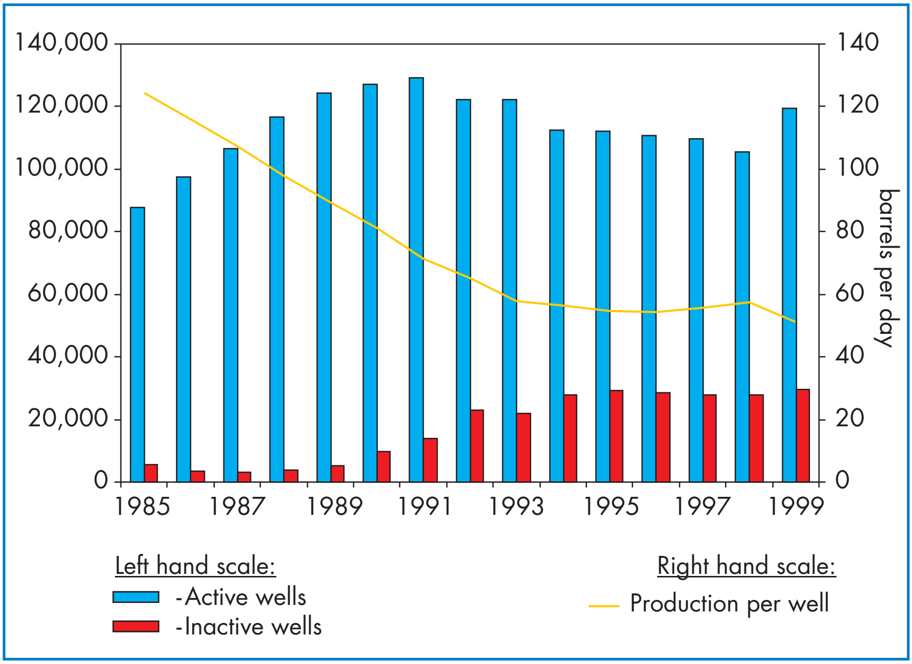
Many producing fields require modern reservoir management to remedy some of the damage caused by past over-production, which in many cases involved quasi-systematic water flooding. Water-flooding, which has traditionally been employed in West Siberia to boost output to maximum levels, has increased the amount of water produced with the oil (water cut). By 1990, the water cut was 76% for Russia as a whole, up from about 50% in 1976. Injection of associated gas was used in only 2% of Russian oil production in 1999. Conversely, the share of oil produced from free-flowing wells dropped from 52% in 1970 to 12% by 1990. By 1999, it was down to 8%. Modern tertiary-recovery techniques will be required to maximise oil recovery.

Russian oil-lifting costs were very competitive in 2001, compared with those of major international oil companies. The estimated average for the publicly-traded Russian oil companies was $2.24 per barrel, with the range from around $1.5 to $3 per barrel. These costs are expected to rise moderately in the period 2001 to 2010 mainly because of the ageing of producing properties and a shift to smaller fields. However, improvements

61. Russian Ministry of Energy (2000b).

62. For example, Mikhail Khordokovsky, Chairman and CEO of Yukos, projects a 7% increase in output for 2001 to 6.8 to 7 mb/d. He forecasts further consolidation and production growth for the whole Russian industry, with output to rise to 8.2 mb/d by 2005 under an acceptable tax regime (presentation 18 June 2001, *Russia in the New Millennium*).

Figure 2.17: **Total Number of Russian Wells and Oil Well Productivity**



Source: PlanEcon, IEA and Russian Ministry of Energy (2000a).

in technology will partly offset these effects, so that Russian costs will remain competitive globally.

The Russian Energy Ministry estimates that investments of approximately $40 billion will be needed by 2010 to reach the production target of 6.7 mb/d.[63] By 2020 it is estimated that a further $80 billion will be needed to reach the production target of 7.2 mb/d. This means average investment of $6 billion per year over the 20-year period. Investment in 2000 was estimated at $5.7 billion, more than twice the comparable figure in 1999.

The net profit of Russian publicly traded oil companies was estimated to have exceeded $14.5 billion in 2000, up from $11.2 billion in 1999 and $4 billion in 1998.[64] With these profits, Russian companies have a lot of internally-generated cash to reinvest in production-capacity growth.

The medium- and longer-term outlooks depend on improvements in the Russian investment environment. Legal, fiscal and regulatory reform

63. Russian Ministry of Energy (2000b).
64. United Financial Group, Troika, *Businessweek* April 2000.

are needed, as well as more transparency, protection for minority-shareholder rights, better corporate practices and the enforcement of the rule of law. PSAs can act as a bridge to attract investment during the period when new legal and tax regimes are being put into place and confidence is being built in them. But much more needs to be done to make the current PSA legislation more effective in promoting major investment projects. Continued tax reform will be required to provide both sufficient incentive and the means to carry out investments. Compared to international norms, Russia's current oil-tax regime relies heavily on volume-based taxes at high combined rates.

Exports

Large increases in oil export capacity are expected over the 2001-2005 period:

- An important development that could help reduce export bottlenecks is the *Caspian Pipeline Consortium* (CPC) initiative. Although this is primarily a project for handling Kazakhstan's expanding oil exports, it has several important implications for Russia. It is the first major pipeline project to be executed by an international group operating in Russia. It will have an initial capacity of 0.56 mb/d per year increasing to 1.34 mb/d by 2015. The bulk of this capacity is reserved for production from Tengiz, but Russian producers will have an allocation of approximately 0.07 mb/d in the first phase.
- The *Baltic Pipeline* project consists of a pipeline extension and a new marine terminal at Primorsk, near St. Petersburg, to serve as an outlet for up to 0.8 mb/d of crude from the Timan-Pechora fields. The first phase of the project calls for the reconstruction of part of the Yaroslavl-Kirishi pipeline, the laying of a new pipeline from Kirishi to Primorsk, and the construction of an oil terminal at Primorsk. This will provide initial export capacity of 0.24 mb/d. Plans to boost capacity to 0.6 mb/d by 2003 would require a more ambitious construction programme. The project may be important in terms of export diversification, but it could have some economic difficulties, not least because the Primorsk site is ice-bound for some six months of the year.
- An independent export terminal is being built in Sakhalin to accommodate local output of 0.26 mb/d by 2005.
- A 0.4-to-0.6 mb/d pipeline from Eastern Siberia to China is planned to start around 2005.

- The effective capacity of the Druzhba pipeline will rise by 0.2 mb/d when it is upgraded and extended to the Adriatic port of Omisalj, tentatively by 2005. A further boosting of Druzhba's capacity along the stretch to the Adriatic may relieve Russia's dependence on oil transit through the Bosporus.
- The *Northern Gateway* proposal is intended to handle increased exports from Timan-Pechora, and as such is a potential competitor to the Baltic pipeline. Initially backed by a consortium of international companies with production interests in the Timan-Pechora region, this project envisions construction of a new oil terminal on the Barents Sea. This would enable producers in the region to bypass the Transneft system altogether and export directly to international markets. Lukoil has proceeded on its own with the construction of a new 0.02 mb/d oil terminal at *Varandey*, where the first tanker was loaded in August 2000. The crude is later transferred to larger tankers in Murmansk. As production increases, capacity is to be expanded to 0.2 mb/d and eventually to 0.3 mb/d.

The Caspian Region

Azerbaijan

Azerbaijan has remaining reserves of 4.5 billion barrels, and undiscovered recoverable resources of 9.2 billion barrels, according to the USGS. The IHS Energy Group has estimated reserves of 9.6 billion barrels at the end of 2000. This includes 4.9 billion barrels in the offshore Azeri-Chirag-deepwater Guneshli (ACG) field, which is operated by the Azerbaijan International Operating Company (AIOC) consortium, led by BP. It also includes some 2 billion barrels in state company Socar's ageing fields. Although almost two dozen production-sharing agreements (PSA) have been signed with international oil companies (IOC) since the early 1990s, IOCs have not discovered any new oil. Offshore exploration is limited by drilling rig availability, although that situation is improving. It will take foreign companies until between 2002 and 2004 to drill all the exploratory wells to which they are committed under the 13 offshore production-sharing contracts now in force (typically 2 to 4 wells per contract).

Azerbaijan's production averaged 300 kb/d in spring 2001 (including 115 kb/d by AIOC, 170 kb/d by Socar, and some 10 to 15 kb/d by small onshore ventures). Azerbaijan's official export targets - which by and large coincide with AIOC's - rise from 170 to 180 kb/d now to 450 to 550 kb/d in 2005 and 800 to 1,200 kb/d in 2010. Additional production and exports may arise from yet undiscovered fields later in the decade (Figure 2.18).

Box 2.8: **Baku-Tbilisi-Ceyhan Pipeline (BTC)**

The BP-led sponsor group for the BTC pipeline will make a final decision about building the 1,745 km pipeline by mid-2002, after completing a detailed engineering study and securing finance. The BTC pipeline will permit the transport of crude by Very Large Crude Carrier from the Turkish Mediterranean port of Ceyhan, rather than by smaller vessels at Black Sea ports. This project is hoped to create synergies with a planned parallel gas pipeline to export Azeri gas to Turkey and to relieve congestion in the Turkish Straits.

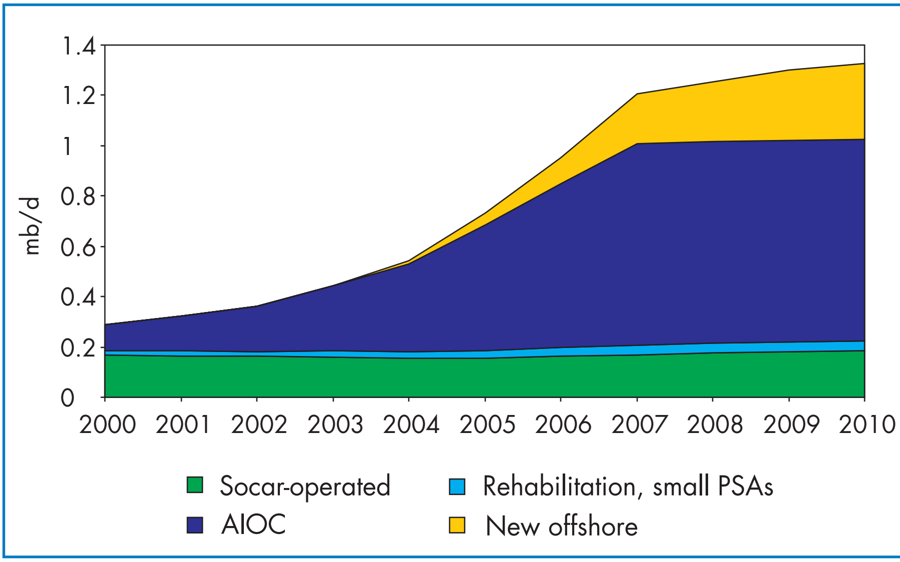
The target date for completion of the line is the end of 2004 or early 2005. The pipeline's capacity will be stepped up in two phases to accommodate production from AIOC's ACG field, from 500 kb/d initially to 1 mb/d by 2008. ACG production could plateau at 1.1 mb/d between 2009 and 2017. This dispenses BTC from securing shipping commitments from other Caspian producers. Existing export pipelines from Azerbaijan to Supsa (Georgia) and Novorossiysk (Russia) with a combined capacity of some 300 kb/d will be underused, unless new Azeri production is brought on stream on top of Socar's current output.

Kazakhstan

Kazakhstan's oil reserves are estimated at 20 billion barrels by the USGS, with a further 24.7 billion barrels assessed as undiscovered. The IHS Energy Group estimates remaining reserves at about 12 billion barrels at the end of 2000. This does not include the as yet uncertified offshore Kashagan field that was discovered in 2000. The largest fields are the Chevron-operated Tengiz field (6 to 9 billion barrels) and the ENI/BG-operated Karachaganak field.

The country's reserves will be boosted significantly by the Kashagan field, which was discovered in the northeastern part of the Caspian Sea by the Offshore Kazakhstan International Operating Company (OKIOC).

Figure 2.18: **Azerbaijan Projected Oil Production**



Source: Company reports, IEA analysis.

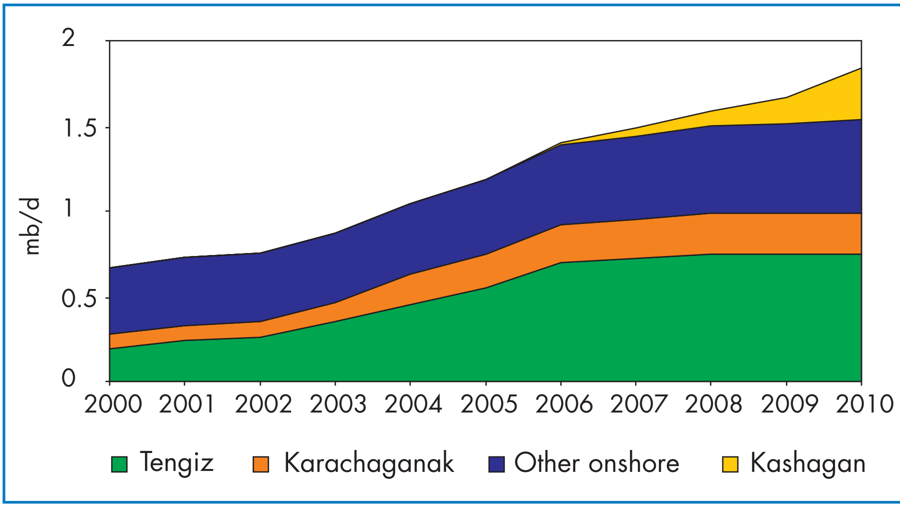
OKIOC operator, the Italian firm ENI, announced in May 2001 that the field's reserves are at least 10 billion barrels based on the two wells that have been drilled. Definitive estimates will not be available before three appraisal wells are completed and an extensive 3D seismic survey is made. In parallel, OKIOC will drill exploratory wells into three promising satellite structures. Kashagan could hold anywhere between 10 and 50 billion barrels of recoverable oil.[65] Kazakh president, Nursultan Nazarbayev, insists that Kashagan oil will start flowing in 2005 - a very difficult target, given the technical and environmental challenges and the sheer size of the field. Other challenges include the need to build a large-sour crude processing infrastructure, a ban on flaring associated gas, a shortage of shipping and fabricating equipment in the region and very shallow water: 2 to 7 metres. Development costs are estimated at $20 billion.

Kazakhstan's production during the first quarter of 2001 was 680 kb/d (a 19% increase over the first quarter of 2000) and is set to rise to almost 800 kb/d for the whole of 2001. Exports averaged 505 kb/d in early 2001. Official production targets stand at 2.4 mb/d by 2010, which is

65. Some of the world's largest oil fields are listed here for comparison (initial reserves in billion barrels): Ghawar (Saudi Arabia, world's largest): 115; Burgan (Kuwait): 66-72.

somewhat optimistic. A more realistic projection would lie in the range of 1.5 to 2 mb/d. This is based on the assumption that Tengiz production will rise from 260 kb/d to 700 kb/d and that Karachaganak production will increase from 90 kb/d to 200 kb/d after linking up with the CPC export line in 2003. Other onshore production (including the large Uzen rehabilitation project) will also increase from 390 kb/d to about 550 to 600 kb/d. On top of this, Kashagan could yield anywhere between 100 to 500 kb/d.

Figure 2.19: **Kazakhstan Projected Oil Production**



Source: IEA analysis.

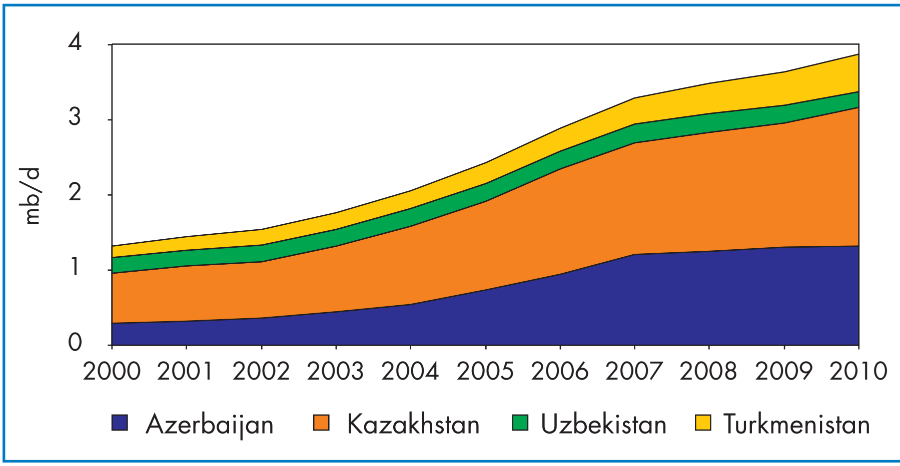
A decision on how to transport Kashagan oil is still several years away. To achieve full production, Kashagan will almost certainly require a dedicated export system. Kazakhstan officially supports a diversification of export routes. The lion's share of Kazakh exports currently transits Russia. Diversification efforts may speak in favour of using the BTC pipeline, but they also support the case for a route through Iran, which is currently under investigation by TotalFinaElf.

The opening of the CPC pipeline to a terminal on the Russian Black Sea in mid-2001 will enable hitherto limited production from the Tengiz field to increase rapidly. The pipeline, with an initial capacity of 560 kb/d, will allow Tengiz production to rise from its current 260 kb/d to a peak of 700 kb/d by 2007. CPC capacity is to be increased to 1.34 mb/d by 2007.

Russia - Caspian Region

In 2000, Lukoil drilled four wells in its Sevenyy licence in the northwestern Caspian and trumpeted oil "reserves" as high as 3.3 billion barrels in two discoveries (Khvalynskaya, Korchagin). These figures may be misleading, insofar as they refer to potential resources. Initial studies suggest that the reserves of Khvalynskaya and Korchagin are probably much smaller than Kashagan in neighbouring Kazakh waters. Russia's three biggest oil and gas companies, Lukoil, Yukos and Gazprom, have formed a joint venture called COC (Caspian Oil Company) to explore a licence off the Volga delta. Further discoveries are, therefore, likely.

Figure 2.20: **Caspian Region Projected Oil Production**



Source: IEA analysis.

Projected Caspian Oil Exports

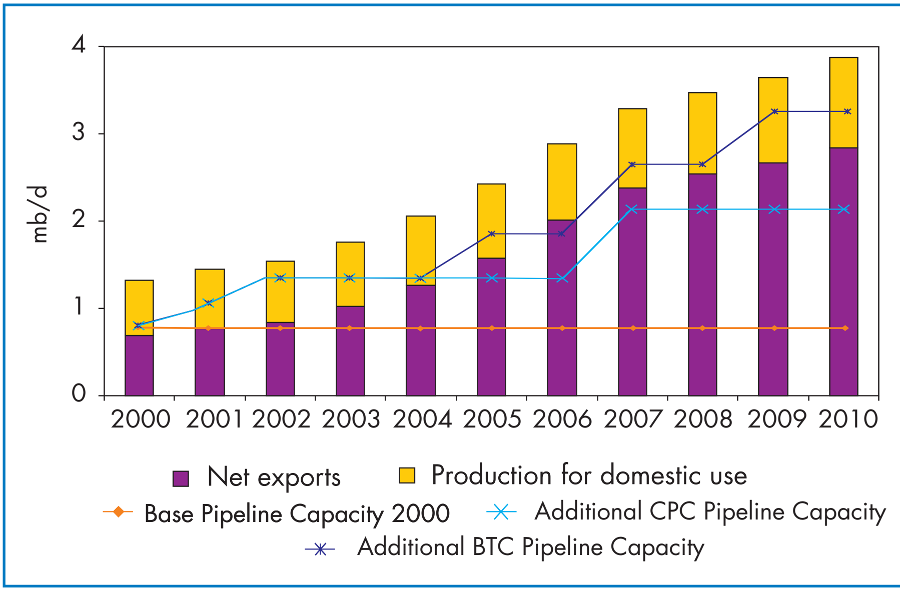
Total oil exports from Caspian countries could reach the 2.4 to 3.5 mb/d range by the end of the decade; i.e. 0.8 to 1.2 mb/d from Azerbaijan, 1.5-2.0 mb/d from Kazakhstan and 150 to 250 kb/d from Turkmenistan. There is likely to be adequate export capacity in place by then, provided BTC materialises as planned (see Figure 2.21). Projections beyond 2010 are more difficult. A moderately optimistic scenario would go like this:

- Significant additional oil reserves are discovered offshore Azerbaijan

- Kashagan proves to be much bigger than Tengiz and surrounded by sizeable nearby reservoirs.
- Turkmenistan's investment climate becomes more predictable; this leads to major exploration efforts, including offshore.
- Legal and operational conditions continue to improve throughout the region, and co-operation with Russia is enhanced.

Under such a scenario, overall Caspian oil exports could exceed 4 mb/d in 2020.

Figure 2.21: **Caspian Region Net Oil Exports and Export Capacity**



Source: IEA analysis.

Box 2.9: **Oil Traffic through the Turkish Straits**

Russian and Caspian oil exports through the Black Sea and Turkish Straits are expected to grow over the next few years. Traffic in 2000 amounted to 1.64 mb/d.[66] With the Russian CPC pipeline coming on stream, tanker traffic is expected to increase to 1.82 mb/d in 2001. This is the maximum tanker traffic the Turkish Straits can handle, according to the Turkish Minister of Maritime Affairs.

Pressure to limit the traffic has grown following a series of accidents in the spring of 2001. The Turkish authorities are installing a new vessel-tracking system and are considering introducing more stringent safety rules. But Turkey's room for the unilateral imposition of safety measures is limited by the 1936 Montreux Treaty, which confers the status of international waterway on the Straits.

A number of developments which will help ease traffic through the Turkish Straits are:

- The Baku-Tbilisi-Ceyhan (BTC) pipeline could be completed in 2005.
- Ukraine will commission its new Odessa/Pivdenny-Brody pipeline around the beginning of 2002. This line may divert 290 kb/d (rising later to 800 kb/d) of oil to Central European refineries.
- Russia is making progress at its Baltic Sea terminal near St. Petersburg (BPS), as part of its strategy to export oil without transiting through third countries. Planned capacity of the system is 240 kb/d. The terminal could open as early as the end of 2001. BPS, although primarily aimed at avoiding Baltic ports, will help reduce Russian Black Sea oil exports (including Kazakh crude transiting through Russia to Odessa).
- The Russian company Yukos is negotiating with Hungary and Croatia about establishing a unified export pipeline to Omišalj terminal on the Adriatic Sea. The plan entails reversing the flow of Croatia's Adria pipeline. Only Ukraine has so far balked at joining the project. The line will allow up to 200 kb/d of Russian crude to avoid the Turkish Straits.
- Demand for Russian or Caspian oil in Romania and Bulgaria could rise along with economic growth. Some 50-100 kb/d of additional Russian and Caspian crude may be offloaded at Romanian and Bulgarian ports in the coming years.

66. 1.18 mb/d of crude plus 460 kb/d of oil products according to the Turkish Ministry of Maritime Affairs.

Saudi Arabia

Overview

Saudi Arabia's economy is the largest in the Middle East. Oil revenues make up 35% to 40% of GDP, 90% to 95% of export earnings and 70% of state revenues. In the year 2000, a combination of higher oil prices and robust production led to a significant improvement in Saudi economic performance, with a growth in real GDP of 4.1%, a reduction of domestic debt and the first budget surplus in 17 years. Lower oil prices during 1998 had swollen domestic debt to 116% of GDP and produced a budget deficit estimated at $12 billion.

In its 2000-2005 development plans, Saudi Arabia's government recognised the need to reduce state involvement and increase private participation and investment in the economy. The opening of selected areas of the energy sector to international investment is part of an international diversification process and is likely to continue in the long term. Encouragement of foreign investment is limited, however, and excludes crude oil production. Investments in natural gas, electric-power generation and the downstream petroleum sector reflect both the country's gradual liberalisation process and its rapid industrialisation and population-growth rates. The expansion of the natural-gas resource base is designed to make gas development one of the main engines of growth.

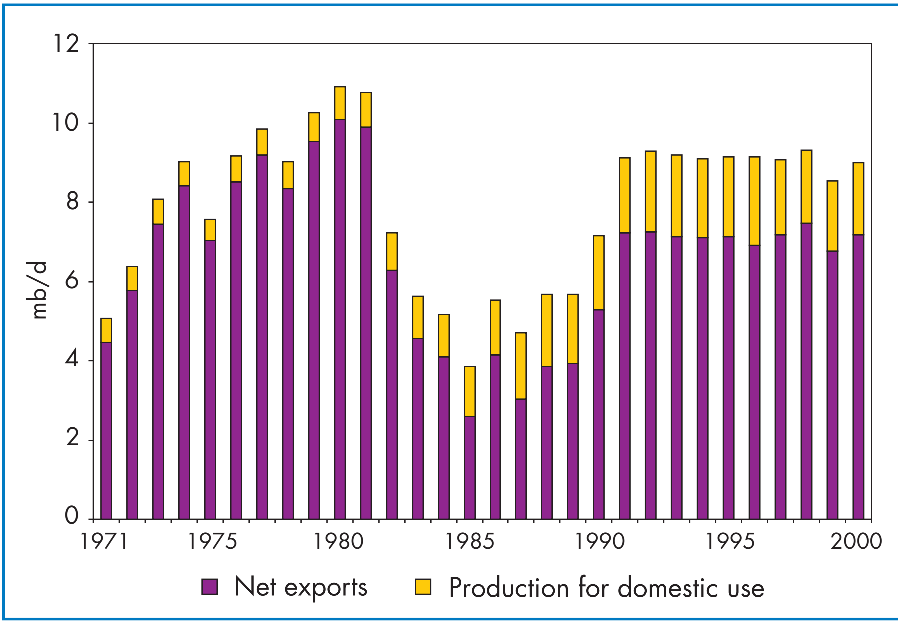
Saudi Aramco, the world's largest integrated oil company, holds a monopoly on hydrocarbon exploration, development and production, as well as on the refining, processing, marketing and distribution of oil and gas products.

Resources and Production Outlook

Saudi Arabia has the world's largest remaining oil reserves, which the USGS 2000 survey estimates at 221 billion barrels. Undiscovered recoverable resources are estimated to be 136 billion barrels. OPEC estimates Saudi reserves at 263 billion barrels (including half of Neutral Zone reserves).

Saudi Arabia is the world's largest oil producer, and given its substantial proven reserves, could produce at 8 mb/d for 75 years, without the discovery of additional reserves. Saudi production during the 80's varied by 7 mb/d from a high of 11 mb/d in 1980 and fell to 4 mb/d in 1985. Saudi achieved a maximum export rate of 10.1 mb/d in 1980 (Figure 2.22).

Figure 2.22: **Saudi Arabian Oil Production and Net Exports**



Note: Production includes NGL.
Source: IEA analysis.

Saudi Arabia's oil production policy is aimed at achieving the following goals:[67]

- maintaining the world's largest oil reserves with production costs among the lowest in the world (officially put at less than $1.50 per barrel[68]);
- maintaining a large spare capacity;
- maintaining the major role of crude oil in the economy;

Official production capacity is 10.5 mb/d. So current excess production capacity is about 2.5mb/d. This represents the majority of global excess production capacity, and it increases Saudi Arabia's strategic importance to world energy markets as well as its position as the swing producer in times of world oil-supply shortfall.

67. *Middle East Economic Survey*, various issues.
68. Prince Faisal Bin Turki Bin Abdul Aziz Al-Sa'ud speech, The Development of Middle East Energy conference, London, 12 February 2001, *MEES,* 5 March 2001.

More than half of Saudi Arabia's reserves is concentrated in just eight fields. The world's largest field, Ghawar, has estimated remaining reserves of 70 billion barrels and accounts for about half of Saudi Arabia's total oil production capacity.

Saudi Arabia has plans to increase its capacity, especially that of relatively light crude oils, to 12.5 mb/d in the coming years. Potential projects include the Qatif field, which could boost Arab Light and Arab Medium production capacity by 500 kb/d at a cost of $1.2 to $1.5 billion.[69] Development of the Khurais field could increase Saudi production capacity by 800 kb/d at a cost of $3 billion. Khurais first came online in the 1960s but was mothballed by Aramco, along with several other fields, in the 1990s. Production capacity of 600 kb/d from the Shaybah field, which contains 7 billion barrels of premium grade 41.6° API sweet crude oil, was estimated to cost $2 to $2.5 billion. This investment includes a 395-mile pipeline to connect the field to Abqaiq, the country's closest gathering centre, for blending with Arabian Extra Light crude.

Aramco plans to drill 292 wells in 2001 at a cost of $1.2 billion, more than double the budget of $580 million for 1999. Many of these wells will be drilled in Ghawar.[70] The Supreme Petroleum Council, the body that oversees Saudi oil and gas policies, has approved total upstream spending of $15 billion per year between 2000 and 2004.

Saudi Arabia's total oil production capacity is made up of about 65%-70% light API gravity crude. Most of the 34° API Arabian Light crude is produced from Ghawar, while 37° API Arab Extra Light crude is produced by the Abqaiq field. Since 1994, the Najd fields have been producing around 200 kb/d of 45°-50° API Arab Super Light, 0.06% sulphur. The Abqaiq field is estimated to contain 17 billion barrels of proven reserves, while the Najd fields are estimated to contain 30 billion barrels of liquids and major reserves of natural gas. Offshore production includes Arab Medium crude from the Zuluf, with over 500 kb/d capacity, and Marjan, 270 kb/d capacity. The Safaniya field produces Arab Heavy crude.

Saudi Arabia's primary oil export terminals have a combined export capacity of about 11 mb/d. They are located on the Arabian Gulf and the Red Sea. Saudi Arabia also claims to have considerable surplus pipeline capacity, including the East-West oil pipeline system, which can carry 5 mb/d. It is currently being run at only half-capacity.

69. http://www.eia.doe.gov/emeu/cabs/saudi.html.
70. http://www.eia.doe.gov/emeu/cabs/saudi.html.

Box 2.10: **Minimising the Cost of Capital for Increasing Production in Saudi Arabia**

Even though the investment required to increase oil-production capacity in Saudi Arabia is much less than in many other parts of the world, the development of oil reserves to meet growing global demand will nevertheless require considerable amounts of capital. Official statements indicate that less than $5,000 of new investment is required for each b/d of new oil production capacity in Saudi Arabia.[71] The capital expenditure to develop production in Saudi is roughly a quarter of that in many other areas of the world; so building Saudi oil supply is a highly efficient use of capital. The cost of this capital will depend on the competition for capital in the market and the risk associated with the returns that investment is expected to generate. It is likely that the cost of capital can be minimised by borrowing on large global capital markets. The risk premium could be reduced through liberalisation of investment and trade flows.

Saudi Arabia has recently announced several changes to its investment law signalling its desire to attract foreign investment and comply with the requirements for membership of the World Trade Organisation. The Saudi Arabian General Investment Authority was formed in April 2000 to facilitate foreign and domestic investment. International energy investment has so far included projects in the electricity and gas sectors. Membership of the WTO is expected to help in the development of new markets, for example, for the country's petrochemical industry.

Iraq

Overview

Oil production in Iraq, traditionally a major producer and exporter, has been constrained in recent years by UN Sanctions following the Iraqi invasion of Kuwait in August 1990. Resolution 661 imposed economic sanctions on Iraq, including a full trade embargo barring all imports from and exports to Iraq, except medical supplies, foodstuffs and other items of humanitarian need, as determined by the Security Council sanctions

71. Prince Faisal Bin Turki Bin Abdul Aziz Al-Sa'ud speech 13 June 2000, WPC Calgary, Canada

committee. In April 1991, Resolution 687, the cease-fire resolution, declared that the full trade embargo against Iraq would remain in place, pending periodic reviews of Iraqi compliance with the obligations imposed under Resolution 687. Resolution 986, passed in April 1995 and implemented in December 1996, enabled Iraq to sell up to $1 billion of oil every 90 days and use the proceeds for humanitarian supplies,. Iraq production increased with various modifications of the "oil-for-food" program, with production peaking in May 2000 at 3.1 mb/d. The oil-for-food program was most recently extended for 150 days from 4 July 2001, by UN Resolution 1360 (2001).

Resources and Production Outlook

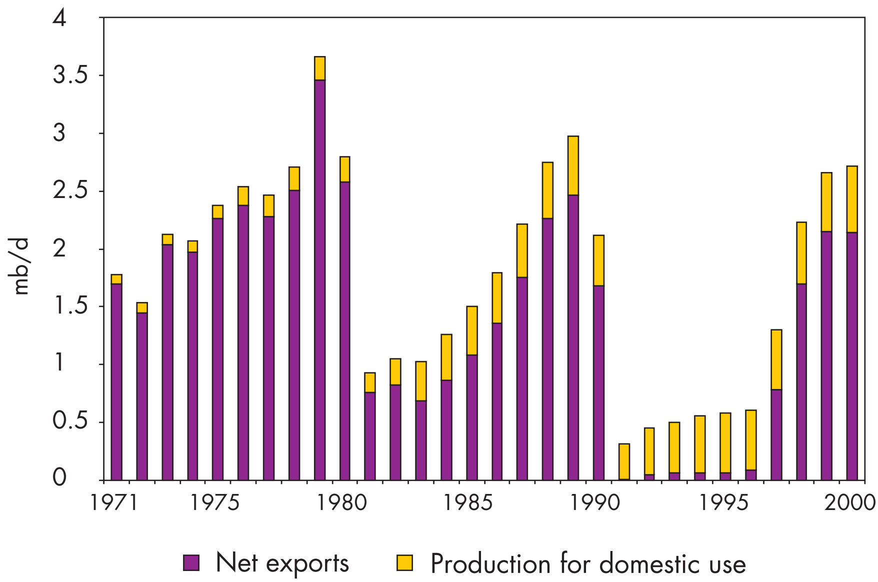
Iraq holds the world's third-largest remaining oil reserves base after Saudi Arabia and Russia, with 78 billion barrels of proven reserves and 51 billion barrels undiscovered according to the USGS assessment. OPEC estimates Iraq's remaining proven reserves at 112.5 billion barrels. Some analysts estimate that exploration in the largely unexplored Western Desert could lift proven reserves to 180 billion barrels.[72]

Iraq's production history has been subject to much uncertainty. Its oil output peaked in 1979 at 3.7 mb/d, yielding exports of 3.5 mb/d. Production fell rapidly in 1980 to 1981 as a result of the Iraq-Iran war. Throughout the rest of the 1980s, production rose until the Gulf War began in 1990. Oil installations were damaged during the war, and subsequent output recovery was constrained by sanctions. Modification of sanctions, and investment under the oil-for-food program has led to considerable growth in production in recent years. (Figure 2.23)

In 2000, a group of United Nations experts visited Iraq to survey the condition of the Iraqi oil sector. Their subsequent report[73] concluded that, under the constraints of the oil-for-food program, an investment of about $1.2 billion raised production capacity from 2.2 mb/d in March 1998 to 3 mb/d in November 1999. This equates to only $1,500 per b/d, indicating the relatively low cost of restoring capacity in Iraq, especially when expressed in dollars. The report puts recent production costs at about 60 cents per barrel, considerably lower than the average in other Middle East countries. This cost includes hard currency operating expenditure plus

72. Arab Petroleum Research Center (2000).
73. Report of the UN Experts Established Pursuant to Paragraph 30 of the Security Council Resolution 1284 (2000).

Figure 2.23: **Iraqi Oil Production and Net Exports**



Source: IEA analysis.

the equivalent of a few cents per barrel for running costs paid in local currency.

Recent activity aimed at maximisation of oil production may, however, have resulted in reservoir damage as well as a general decline in the quality of oil produced. For example, the production of Kirkuk, discovered in 1927, has declined from 1.4 mb/d before 1990 to about 800 kb/d at the beginning of this year. (Table 2.15) Without carefully monitoring of the water-injection program, irreversible damage to the reservoir of this super-giant may be approaching. Official reports project that Kirkuk output may fall to 600 kb/d by 2004. In light of the fast decline in production, attention is centred on sustaining output from mature fields in the North as well as increasing production from Southern fields.

The UN report raises concerns about the impact that the current low level of investment may have on future production and ultimate oil recovery. Because of inadequate reservoir management and water-drive facilities to extract oil from the reservoir, some of the sandstone reservoirs in the south may only have ultimate recovery factors of between 15% and

Table 2.15: **Iraq's Current Producing Oil Fields (March 2001)**

Company	***Production*** *(kb/d)*
South Oil Company (SOC)	
South Rumaila	700
North Rumaila	350
Zubair	155
West Qurna	140
Missan	40
Luhais	30
Bin Umar	5
Total SOC	1,420
North Oil Company (NOC)	
Kirkuk	800
Bai Hassan	100
Jambur	75
Khabbaz	25
Saddam	25
Ain Zalah	8
Sufaya	8
Total NOC	1,041
Total NOC and SOC	2,461

Source: Petroleum Argus, 2001 Special Report: Iraq, 19 March 2001.

25% of oil volumes-in-place. If not addressed, this will result in considerable amounts of oil that cannot be recovered. The industry norm for analogous reservoirs in other countries is in the 35% to 60% range. The use of modern oilfield technologies, such as horizontal drilling, 3D seismic acquisition and simulation of reservoir production, should raise ultimate recoveries in Iraqi reservoirs to between 35% and 50%.

Iraq hopes to achieve its production target of 6 mb/d by developing the country's largest oil fields (see Table 2.16) as well as by finding and developing oilfields in the Western Desert. Reaching this target will depend on access to equipment, technology and investment. Iraq estimates that this will cost about $21 billion and the target could be reached within eight to ten years of sanctions being lifted.[74] Projects that are to be

74. APRC (2001).

developed under twelve-year Development and Production Contracts (DPCs) have been put on hold pending the lifting of sanctions. The projects involve 25 undeveloped and 8 partially developed fields. Iraq will hold 10% of the equity.

Table 2.16: **Proposed Post Sanctions Development and Production Contracts**

Field	***Planned Production*** (kb/d)	***Reserves*** (million barrels)	***Companies***
Majnoon	600	12,100	TotalFinaElf
West Qurna	810	11,320	Lukoil-led consortium
Nahr Bin Omar	450	6,266	TotalFinaElf
Halfaya	250	4,610	BHP, CNPC, Korean consortium
Rattawi	250	3,134	Petronas, CanOxy, Crescent
Nassiriya	300	2,623	ENI, Repsol
Tuba	200	1,529	Pertamina, Sonatrach, Reliance
Gharaf	130	1,134	TPAO, Japex
Rafidain	100	688	Perenco, Sidanco, Tattipneft, JNPC
Amara	80	486	PetroVietnam
Total	**3,170**	**43,890**	

Source: *Middle East Economic Survey,* 16 July 2001.

Iran

Overview

Iran's GDP growth for 2000 was 4.5%, the highest in recent years, and a clear reflection of the firmer oil prices in 2000. Oil export revenue accounts for about 80% of Iran's total export earnings and 40% to 50% of the government budget. Iran's foreign debt shrank in 2000 from $10.4 billion in March 2000 to $8.7 billion in December 2000.

Iran has created an oil-stabilisation fund to hedge against fluctuations in oil prices. Revenue from oil exports at prices above the budgeted oil price will be placed in this fund. This should cushion the economy from future fluctuations in the oil price and ensure that the government balance sheet is strengthened when oil price movements are favourable. The fund will also be used to promote the private sector and exports. The extent to which hydrocarbon exports will continue to fuel the economy will be affected by rising local consumption of oil (Figure 2.24), local subsidies[75] and the liberalisation of the economy.

Figure 2.24: **Iranian Oil Production and Net Exports**

Source: IEA analysis.

Resources and Production Outlook

According to the USGS 2000 assessment, Iran has abundant remaining oil reserves of 76 billion barrels, and undiscovered recoverable resources of 67 billion barrels. The OPEC Secretariat estimates that Iran has remaining reserves of 100 billion barrels.

Successive political upheavals, an eight-year war with Iraq, and energy policies that alienated potential investors, have significantly reduced the development of the country's hydrocarbon resources. Iran's annual production declined from a peak of 6.4 mb/d in 1974, when its exports were 5.7 mb/d, to about 3.7 mb/d in 2000, with exports of around 1.8 mb/d. Production in 2000 was the second highest in OPEC and the fourth highest in the world.

75. The impact of energy subsidies on the Iranian oil market, and net exports, is analysed in IEA (1999).

NIOC plans to raise production from 3.75 mb/d at the beginning of 2001 to 5 mb/d by 2003 and 8 mb/d by 2020.[76] In the short-term, production under foreign buy-back contracts is expected to contribute about 1.1 mb/d (compared with 100 kb/d in 2000). Several recent discoveries have been made, including the 26 billion barrel Azadegan field, two onshore fields near Gavaneh and several new reservoirs in existing fields. NIOC estimates Azadegan to have a production potential of 400 kb/d. The finding, development and production costs in Iran are estimated at $4.2 per boe.[77]

Iranian production prospects will depend to a significant extent on access to finance and modern technology. The opening of the petroleum sector to international oil and gas companies gained momentum in 1998, when 24 new oil and gas projects as well as 17 onshore and offshore exploration blocks were put on offer. Since it reopened to foreign investment in the energy sector, Iran has used the buy-back model for upstream oil contracts. The buy-back model is essentially a service contract under which international oil companies carry out exploration and development operations. The contractor funds the initial investment and receives remuneration from NIOC in the form of an allocated production share. At the end of the contract, the operation of the field is transferred to NIOC. Under the buy-back agreement, the contractor receives a fixed rate of return, and NIOC bears the risk of lower revenues if oil prices fall. Iran has recently implemented an enhanced buy-back structure that is expected to improve investment incentives for foreign contractors.

Kuwait

Overview

Kuwait's economy is strongly influenced by oil revenues. Kuwait's real GDP grew by about 5.5% with the relative high oil prices in 2000, compared with a fall of 10.5% with the low oil prices of 1998. Government economic policy aims to encourage private-sector growth through a series of reforms designed to increase domestic and foreign direct investment. The large amount of legislation in preparation, as well as the many further initiatives under consideration, indicates Kuwait's political will to create an investment-friendly environment. The opening of the banking sector to

76. Arab Petroleum Research Center (2000).
77. ENI (2001).

Table 2.17: **Contracts under Buy-Back Terms**

Field	*International Oil Companies*	*Date of Award*	*Additional Capacity kb/d*
Sirri A&E	TotalFinaElf, Petronas	July 1995	120
South Pars	TotalFinaElf, Gazprom, Petronas	September 1997	80
Doroud	TotalFinaElf, ENI	March 1999	85
Balal	TotalFinaElf, Bow Valley, ENI	April 1999	70
Soroush/Nowruz	Shell	November 1999	190
Darquain	ENI	June 2001	180
Cheshmeh Khosh	Cepsa	Ongoing	71
Bangestan Formations:	Shell, TotalFinaElf, ENI	Ongoing	860
Ahwaz*	BP, Lasmo		340
Mansuri			350
Ab Teymour**			170
Azedagan	Japanese consortium (Japex, Inpex, Tomen, JNOC)	Under Negotiations	n.a.

Source: Arab Petroleum Research Center (2000), *Middle East Economic Survey*, 2nd July, 2001 foreign financial institutions and the dismantling of the state monopoly on air services are the latest reforms pushed by the government.

Kuwait's constitution does not permit the award of concessions that would transfer the ownership of Kuwait's natural resources to foreign entities. Since 1975, however, foreign oil companies have provided technical assistance and construction and maintenance services under contracts which pay them for specific services. The government is now investigating ways to involve foreign companies in increasing production without violating the constitution. The new "Operating Service Agreements" being considered by the government would allow the Kuwaiti government to retain full ownership of its oil reserves. Foreign firms would be paid a "per barrel" fee, along with allowances for capital recovery and incentive fees for increasing reserves.

Resources and Production Outlook

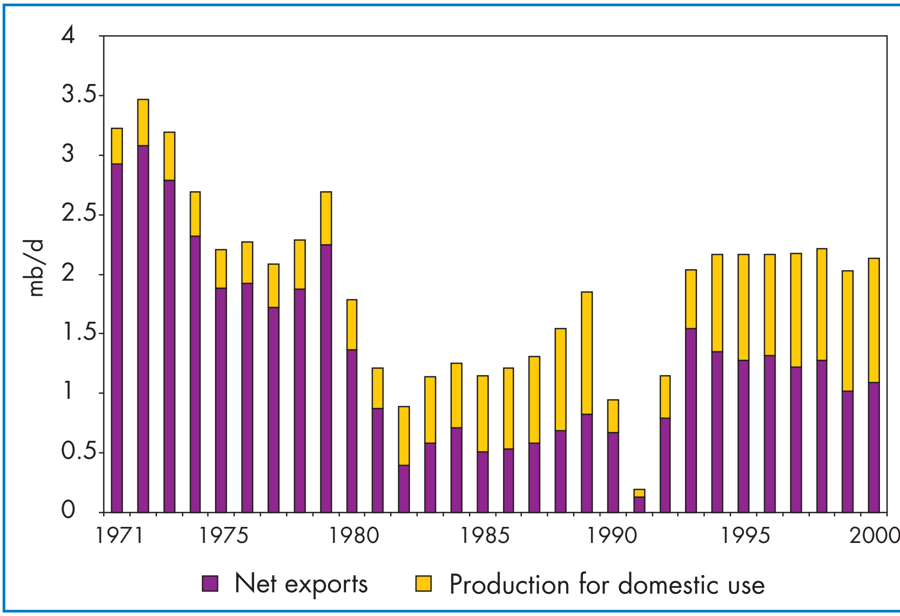
The USGS *2000 Assessment* estimates that, as of January 1996, Kuwait had remaining reserves at 55 billion barrels and undiscovered recoverable resources of 4 billion. OPEC puts Kuwaiti reserves at 96.5 billion barrels (including half of Neutral Zone reserves). Most of Kuwait's producing oil fields are located in the south, notably in the Greater Burgan area, which groups the Burgan, Magwa and Ahmadi structures. Greater Burgan is the world's second-largest oil field after Saudi Arabia's Ghawar.

Kuwait's crude oil exports peaked in 1972 at over 3 mb/d, with total production of 3.5 mb/d. The majority of current production comes from the Greater Burgan field, discovered in the 1930's and 1950's. The Burgan, Ahmadi and Magwa structures produce a combined 1.6 mb/d. Production from smaller fields include Raudhatain (225 kb/d), Sabryia (160 kb/d), Minaghish (60 kb/d) and Umm Ghudair (60 kb/d). Additional output is planned from Bubyan Island where exploratory work is set to begin. The finding, development and production costs in Kuwait are estimated at about $4 per barrel.[78]

Kuwait is a member of OPEC and production is constrained by quota agreements. The Kuwaiti government is pushing for an expansion of production capacity from the present 2.4mb/d to over 3.5 mb/d by 2010.[79] In order to achieve this production increase, Kuwait is considering permitting foreign oil companies to invest in upstream production through an initiative called *Project Kuwait*. This project involves increasing

78. ENI (2001).
79. EIA country analysis website.

Figure 2.25: **Kuwaiti Oil Production and Net Exports**



Source: IEA analysis.

production at existing oil fields in northern and western Kuwait, including Rawdaitain, Sabriyah, Ratqa, Abdali, and Bahra. The project aims to attract investment of about $7 billion to increase production capacity by about 450 kb/d, to reach 900 kb/d by 2010. Foreign consortia are expected to add to Kuwait's reserves through effective reservoir management that will improve oil recovery. They are also expected to develop more challenging reservoirs and to provide and implement the technologies required for enhancing oil recovery projects.

Kuwait-Saudi Neutral Zone

Under a 1992 agreement, the Neutral Zone is a 6,200 square-mile area divided equally between Kuwait and Saudi Arabia. USGS estimates reserves in the Neutral Zone at 8.5 billion barrels. OPEC apportions reserves from the Neutral zone to Saudi Arabia and Kuwait in equal measures. Oil production in the Neutral Zone, about 600 kb/d in 2000, is exported from area terminals. The producing fields were discovered in the 1950s and 1960s and produced 5 billion barrels of oil up to the beginning of 1996 (the effective date of the USGS 2000 assessment). The remaining

8.5 billion barrels of reserves would give a reserves to production ratio of around 37 years at current production rates. This is lower than Kuwait's 85 years, and Saudi Arabia's 76 years.

West Africa

Regional Overview

Exploration and Production

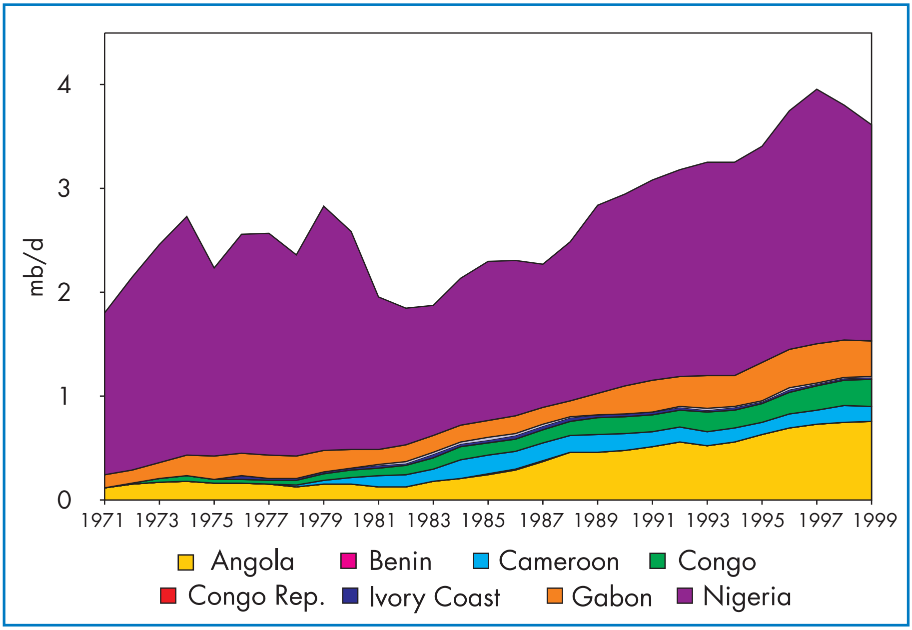
Licensing of exploration and production acreage has surged along the entire western coast of the African continent since the mid-1990s, with the total area licensed now exceeding two million sq. km. All West Africa coastal states except Togo and West Sahara have granted exploration licences.[80] But exploration remains focused on the Gulf of Guinea (from Nigeria to Angola's Kwanza basin). Although there have been encouraging drilling results elsewhere, including offshore Mauritania, exploration beyond the Gulf of Guinea is confined to high-risk frontier prospects.

Aggregate oil production rose steadily through the early 1990s to a peak of 3.86 mb/d in 1997 (Figure 2.26), then declined during the oil-price crunch years of 1998 to 1999. Approximately 60% of the region's production comes from offshore fields.

Nigeria remains by far the leading producer, with 2 mb/d in 2000. Angola is second, with sustained production growth from 470 kb/d in 1990 to 760 kb/d in 2000 and abundant reserves for further growth. Congo-Brazzaville has seen its output rise from 155 kb/d in 1990 to 270 kb/d in 2000. Equatorial Guinea began producing small amounts of oil in 1996. Although production is currently modest, the country's production could reach 300 kb/d by 2003. Gabon has maintained production between 260 kb/d and 380 kb/d throughout the decade, but is facing rapid depletion of its ageing fields with little potential to replenish reserves. Cameroon, whose production has slowly decreased from more than 150 kb/d in 1990 to 120 kb/d in 2000, lacks the reserves needed to restore its lost output.

80. The waters off West Sahara are viewed as promising by oil companies, but licensing can proceed only after a referendum on the territory's status takes place under UN supervision. Even war-torn Liberia and Sierra Leone have acquired speculative seismic surveys off their coasts in view of international bidding.

Figure 2.26: **West African Oil Production**



Source: IEA analysis.

Resources and Reserves

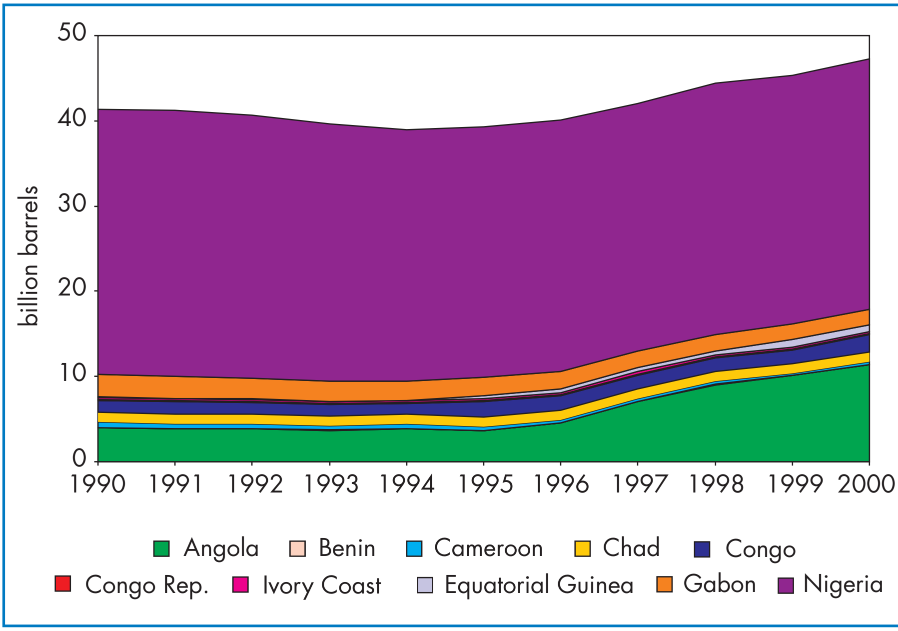
West Africa has witnessed an impressive streak of new oil field discoveries and reserves growth over the past decade. Figure 2.27 shows net proven oil and NGL reserves. The figure takes into account both reserves additions as well as reserves depletion from production. Over the past decade, the region's overall reserves increased by almost 6 billion barrels to 47.2 billion barrels at the end of 2000.[81] The USGS estimate remaining reserves at 29 billion barrels, with 110 billion barrels of undiscovered recoverable resources as of 1 January 1996. This corresponds to a comfortable R/P ratio of 36 years.

The lion's share of newly discovered reserves is in Angola's deep waters. The country's reserves soared from under 4 billion barrels in 1990 to 11.4 billion barrels in 2000. Nigeria outweighs all other countries in the region, with 25 to 29.3 billion barrels,[82] almost 2 billion barrels less than in

81. IHS Energy (2000).

82. NNPC's current estimate of reserves is 25 billion barrels. Other estimates range from 22.5 billion barrels (BP) to 29 billion barrels (IHS Energy, 2000). Nigeria Presidential Advisor Dr. Rilwanu Lukman, former Secretary General of OPEC, quoted a figure of 27 billion barrels of reserves in early 2001.

Figure 2.27: **West African Remaining Oil Reserves**



Source: IHS Energy.

1990. Congo-Brazzaville has boosted its reserves by some 20% to just over 2 billion barrels in 2000, as a result of resumed exploration following the abating of civil strife. Land-locked Chad has 1.14 billion barrels waiting to be produced and exported, starting in 2003, through the 1,050-km Chad-Cameroon pipeline now under construction. Chad's production will peak at some 225 kb/d to 250 kb/d. Equatorial Guinea, although it has received much attention for its fast-track development, has only 0.8 billion barrels of reserves. Gabon's reserves have decreased from 2.6 to 1.8 billion barrels. Cameroon, Ivory Coast, Congo-Kinshasa, and Benin each have reserves of 300 million barrels or less.

Resources and Production

A recent study indicates that 15.8 billion barrels of reserves distributed over 176 fields could be brought on stream in the coming five years.[83] Capital expenditures needed to develop these fields have been calculated at $35.3 billion. New fields could increase the region's output by almost 3 mb/d later in the decade, but there is some uncertainty as to the commitment and timing of the investment.

83. Douglas Westwood (2000).

Table 2.18: **Offshore West Africa - Projected Investment in the Next Five Years** ($ billion)

Angola	15.65	Côte-d'Ivoire	1.76
Benin	0.04	Eq. Guinea	1.45
Cameroon	0.98	Gabon	1.58
Congo-Brazzaville	1.86	Ghana	0.71
Congo-Kinshasa	0.06	Nigeria	11.21

Source: Douglas-Westwood and Infield Systems (2000).

Based on today's proven reserves, West African oil production could rise from some 3.6 mb/d in 2000 to as much as 5.6 mb/d in 2005. This estimate is based on the assumption that production build-up will not be impaired by constraining factors. These might include Nigeria's compliance with OPEC decisions; Angola's voluntarily limited oil development policy; and possible delays caused by the technical problems of deepwater development or by political turbulence in some countries. Longer term, projections become more hazardous, as production from as-yet-undiscovered reserves may come on stream.

Nigeria

The maximum sustainable production capacity of Nigeria, an OPEC member, is estimated at 2.2 mb/d.[84] Nigeria's operations suffer from chronic sabotage of materials, labour conflicts and community protests. As a result, the country's *real* production capacity is much lower than it might otherwise be. Official plans call for increasing production capacity to 3 mb/d in 2002 and 4 mb/d in 2010. These targets, as such, are not unrealistic, but the 2002 deadline is probably too optimistic. Nigeria's OPEC obligations could become a major issue, if the government were forced to curtail output sharply to comply with its quota. So far, the Nigerian National Petroleum Corporation (NNPC) has not had to cap foreign-operated output with heavy-handed decrees, because operational difficulties have "naturally" constrained production.

Since he was elected in 1999, President Olusegun Obasanjo has taken steps to fight endemic corruption in Nigeria. He dissolved the Ministry of Energy, revoked the exploration licences of dozens of domestic companies and blacklisted smuggling oil traders. But many fundamental problems

84. OPEC Secretariat.

Table 2.19: **West Africa - Projected Oil Production** (kb/d)

	1999	2000	2001	2002	2003	2005	2010
Angola	765	761	790	900	1,050	1,450	1,600-2,000
Cameroon	122	120	100	90	70	65	50
Congo-Brazzaville	230	270	263	270	280	300	300
Equatorial Guinea	85	126	160	220	270	300	300
Gabon	309	261	280	280	270	250	200
Nigeria	1,880	1,999	2,100	2,250	2,500	3,000	3,000-4,000
Chad	0	0	0	0	50	200	250
Others*	32	32	30	30	40	50	100
Total	**3,425**	**3,569**	**3,725**	**4,040**	**4,530**	**5,600**	**5,800-7,200**

* Others include: Benin, Congo-Kinshasa, Ivory Coast. Other countries where exploration is currently underway are unlikely to bring reserves on stream before the second half of the decade.
Source: IEA analysis.

have not been tackled yet. The country has, nonetheless, enjoyed improved ratings from international banks. TotalFinaElf's deepwater Amenam development is tapping into international capital markets for finance, something that would have hardly been conceivable a few years ago. The country's first open international tender in 2000 sparked considerable interest, with new and reputable companies appearing on the Nigerian stage. In 2000, the International Monetary Fund provided a $1 billion structural-reform facility to alleviate Nigeria's external debt, estimated at some $38 billion.

Some 90% of Nigerian oil is produced by six joint ventures with major international oil companies. NNPC usually holds a typical 55% or

Table 2.20: **Deepwater Field Developments**

Operator	Field	Capacity, start-up
ENI	Abo	50 kb/d, mid-2002
Shell	Bonga	225-280 kb/d, April 2003
ExxonMobil	Erha	220-250 kb/d, 2004?
Texaco	Agbami	200 kb/d, 2004?
Shell	EA/EJA	100 kb/d, 2003
TotalFinaElf	Amenam	100 kb/d, mid-2003

Source: Press and company reports.

60% stake in these ventures. However, they often suffer from under-funding, because NNPC is unable to finance its share of the venture. NNPC's 2001 budget calls for it to contribute $6.1 billion to joint ventures, of which $3.53 billion is to be paid directly by the treasury. The government recognises the problems in financing the joint ventures, but efforts to sell state equity in these have so far failed because of feared loss of face and fierce institutional opposition. Recent contracts have been structured as Production Sharing Agreements, leaving operational control to foreign operators and dispensing NNPC from up-front funding.

Most future oil production growth will stem from deepwater developments. These large projects will add 800-850 kb/d of new production during the second half of the decade. There are also smaller field-development projects, both on land and offshore, which could add some 150-200 kb/d of production in the coming few years. Additional production will come from some 116 marginal fields containing 1.3 billion barrels, which are being offered to Nigerian oil firms. The indigenous private sector currently accounts for about 5% of total production.

Vandalism constantly disrupts oilfield operations and has caused spillage of some 2.8 million barrels of oil into the Niger Delta since 1985. About 1,200 incidents are reported each year. Nigeria pegs its sabotage-induced losses at some $4 billion/year. The perpetrators are from disgruntled communities, who feel that they do not have an equitable share of oil revenues. The government is currently reviewing allocation of oil revenues between the federal government and the southern oil-producing states.

Angola

Angola has been one of the world's exploration hotspots ever since Elf made its first giant oil discovery, Girassol, in 1,365 metres of water in April 1996. Since then, 5 to 7 billion barrels of reserves have been discovered in water depths between 400 and 1,400 metres in the Kwanza basin off the northwestern coast of Angola. TotalFinaElf, ExxonMobil, BP and Chevron have scored exploration successes of 90% or more, as almost every wildcat struck commercial oil. The exploration success of the deepwater Kwanza basin has prompted BP, TotalFinaElf and ExxonMobil to sign up for ultra-deepwater blocks in up to 3,000 metres of water.

The deepwater discoveries have aroused hopes for a massive and rapid production increase. Chevron, TotalFinaElf and ExxonMobil have launched multi-billion dollar development schemes. In the near term,

Table 2.21: **Angola Deepwater Discoveries**

Operator (Block)	***Field***	***Reserves,*** *(million barrels)*	***Development***
Chevron (14)	Kuito	n.a.	On stream in 1999, production rate 75 kb/d, instead of 100 kb/d planned
	Benguela-Belize	n.a.	Early study stage
	Landana, Lobito, Tomboco	n.a.	No development plan yet
TotalFinaElf (17)	Girassol	725	Start-up late 2001, 200 kb/d
	Dalia	860-1,000	2004
	Rosa, Lirio, Orquidea	n.a.	Development decision in 2002, possible start-up in 2005
	Cravo, Jasmim, Camelia, Tulipa, Perpetua	n.a.	
ExxonMobil (15)	Kizomba (includes Kissanje, Marimba, Hungo, Dikanza, Chocalho, Xicomba, Mondo, Batuque, Saxi)	3,500 (oil equivalent)	2004 at the earliest, 250 kb/d
	Mbulumbumba, Vicango		
BP (18)	Platina, Plutonia, Paladio, Galio, Cromio, Cobalto	about 1,000	Unlikely before 2004-05

Source: Press and company reports.

however, it is doubtful whether the country will achieve its declared target of 830 kb/d in 2001. The potential for massive production increases certainly exists, but the production build-up is likely to be more protracted than was assumed earlier.

The entry of international oil companies into Angola has bolstered the position of the state-owned oil company, Sonangol, which has stiffened contract terms and procedures, insisting on the "Angolanisation" of oilfield services. In 2000, Angola began to elaborate a new long-term policy which seeks to extend the lives of fields to ensure revenues for future generations. This policy shattered earlier predictions that Angola would almost double its production to 1.4 mb/d by 2003. Foreign oil companies were dismayed, since optimal deepwater-field development requires fields to be developed rapidly in hubs and clusters to reduce costs.[85] Moreover, Sonangol has rejected ExxonMobil's development plan for the deepwater Kizomba complex, because the company had not respected certain technical procedures in its $3.1 billion tender.

The final version of the long-term policy has not yet been published. The government seems to have become more conciliatory towards foreign companies in 2001, conceding that the new strategy would apply only to newly signed contracts and that contracts already in force would not be affected. Nonetheless, deepwater developments are already suffering delays and technical difficulties. Chevron has not yet reached the planned 100 kb/d plateau for production at Kuito, Angola's first deepwater development, which was brought on stream in December 1999. Production at Kuito has stabilised at 70 kb/d to 75 kb/d. TotalFinaElf's flagship Girassol project is running about a year behind schedule, with first oil expected in late 2001. The French company has pushed back the start-up date for its next field, Dalia, from 2002 to 2004. It has yet to make development decisions for the eight other discoveries in Block 17. This means that none of them will come on stream before the second half of the decade. ExxonMobil's first deepwater development, Kizomba, is unlikely to go on stream before 2004.

85. TotalFinaElf reports development and production costs of $6 to $6.20 per barrel for Girassol. Finding costs for Block 17 are estimated at about 20 cents per barrel.

Box 2.11: **Maritime Border Issues**

Delineation of the maritime boundaries in the Gulf of Guinea has become a necessity since exploration has moved into deeper waters. So far, disputes have been resolved amicably. Four countries, Nigeria, Cameroon, Equatorial Guinea and Sao Tome e Principe have, or had, conflicting claims in the Gulf. Two disputes have been resolved so far. In September 2000, Nigeria and Equatorial Guinea signed a treaty defining their common offshore boundary. Resolution of this issue had become urgent, since ExxonMobil was developing the Zafiro field in Equatorial Guinean waters. TotalFinaElf subsequently discovered the Ekanga field in adjacent Nigerian waters. Zafiro and Ekanga finally proved to be one and the same field. Nigeria waived its earlier claim to Zafiro, and both countries decided to apportion areas of Zafiro and Ekanga. In February 2001, Nigeria and Sao Tome agreed jointly to explore and exploit a formerly disputed zone. The longest-lasting dispute in the area involves Nigeria and Cameroon, which both hold claims to the 1,000-sq. km Bakassi peninsula and the shelf that extends off its shores. This issue led to armed hostilities in 1994. The case was brought to the International Court of Justice, where proceedings continue.

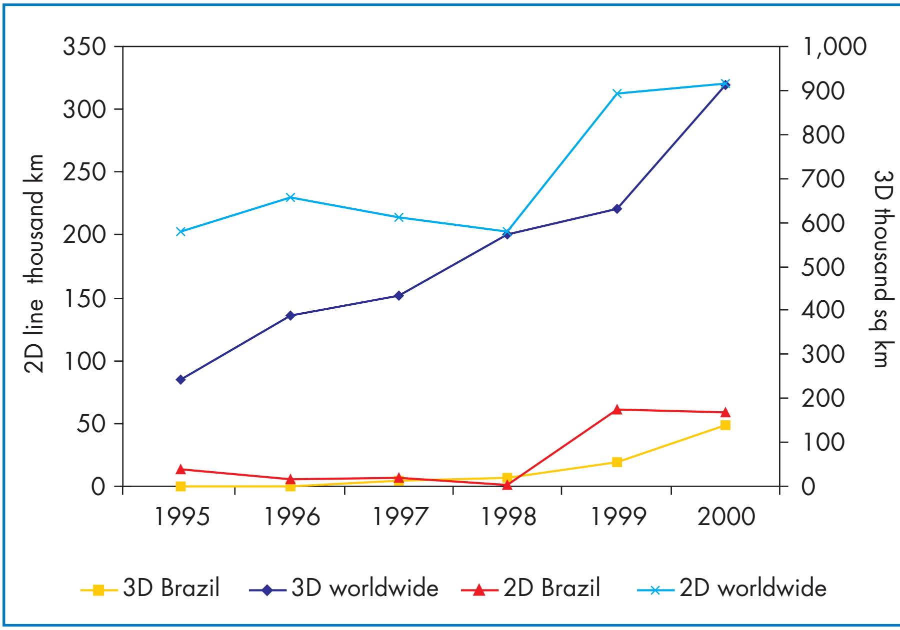
Brazil

Overview

The Brazilian oil sector has undergone major changes over the past five years. In 1997, the National Petroleum Agency, *Agencia Nacional do Petróleo* (ANP) was created to oversee the transition of the oil industry from a heavily regulated, state-controlled sector to a competitive sector able to attract private investment. In 1998, ANP announced that 92% of Brazil's sedimentary basins would be opened for bidding, effectively ending the 45-year monopoly of Petrobras, the state oil company.

The first round of bidding in 1999 generated $187 million in revenues and opened relatively unexplored but highly promising areas in deep-water areas to 10 foreign firms. The second round, concluded in June 2000, offered 23 blocks in nine basins and earned $260 million. The third round, in June 2001, yielded $250 million for 53 exploratory blocks, the most attractive of which are offshore in the Campos, Santos and Espirito

Figure 2.28: **Seismic Acquisition: Brazil and Worldwide**



Source: IHS Energy (2000).

Santo basins. Exploring these deep-water blocks demands a high level of technical know-how. The success of these rounds and the large amounts of capital raised will encourage ANP to continue to hold annual licensing rounds. In advance of exploration and development drilling, a large amount of 3D and 2D seismic data has been acquired in Brazil. In 2000, Brazil accounted for 15% of the world's 3D seismic acquisition and 18% of 2D seismic acquisition (Figure 2.28).

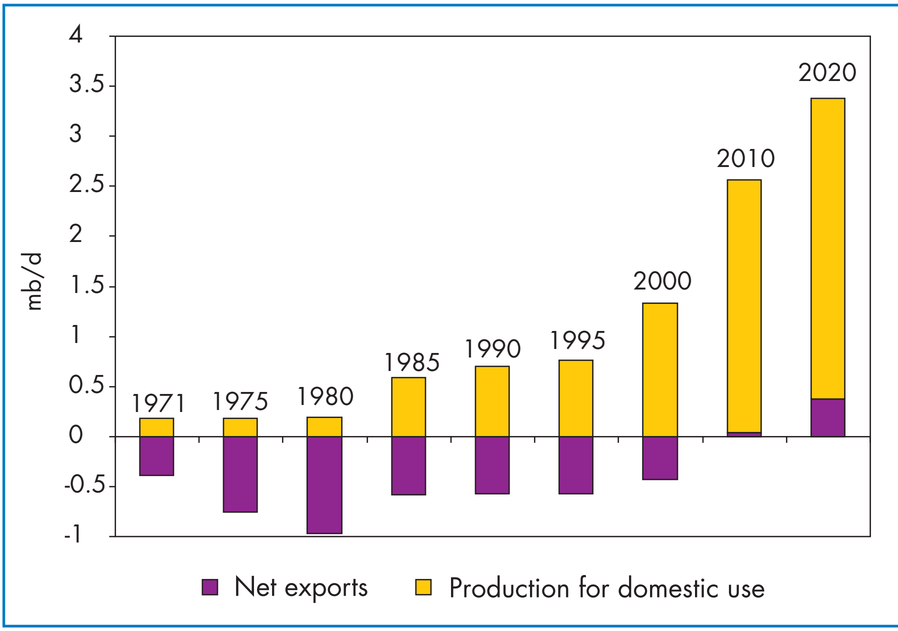
Resources and Production Outlook

After Venezuela and Mexico, Brazil contains the third-largest remaining oil reserves in Latin America, at 8.9 billion barrels. Brazil also has some 47 billion barrels of undiscovered recoverable resources, and 8 billion barrels of undiscovered recoverable NGL, almost all in offshore fields.[86]

From 1995 to 2000, domestic oil production rose 60% from 0.94 mb/d in 1995 to 1.5 mb/d.[87] Further increases in Brazilian

86. USGS (2000).
87. (IEA, 2001a) Production data for Brazil includes about 230 kb/d for unconventional oil, principally ethanol used as a fuel for transportation.

Figure 2.29: **Brazilian Oil Production and Net Exports**



Source: IEA analysis.

production are likely to result from the introduction of private capital, the more competitive environment and increasing foreign participation in exploration and production. Production, including unconventional oil, is expected to reach 2.6 mb/d in 2010 and 3.2 mb/d in 2020, while demand moves to 2.5 mb/d in 2010 and 3 mb/d in 2020. These projections imply that Brazil will reach self-sufficiency and should become a net oil exporter in the future.[88]

The National Petroleum Agency estimates that the petroleum industry as a whole, including numerous new players, will invest $40 billion over the next five years. Some 70% of Petrobras outlays will go to exploration and production, focusing on deep water. Petrobras maintains the world's deepwater drilling and production record, with production from a well drilled in a water depth of 1,853 metres. About 23% of Brazilian reserves are found in water depths of between 1,000 and 2,000 metres. It is expected that about half of the resources yet-to-be discovered will be found at similar depths.

88. Several sources share this view, although the timing is surrounded by uncertainty. See, among others, *Petroleum Intelligence Weekly*, "Brazil to be a Net Exporter, Question is When", 10 April 2000; *The Petroleum Finance Company*, "Brazil's oil sector: Reforms Set Stage for Growth", August 2000.

In May 2001, Petrobras reduced its 2001 production target by 30 kb/d to 1.39 mb/d following the sinking of the P-36 platform in March. This platform had produced 80 kb/d.[89] To compensate for the lost production, Petrobras will ramp up production at the Marlim Sul field more quickly than previously planned. In 2002, the company expects to produce about 1.5 mb/d. It foresees that its oil and NGL production in Brazil will reach 1.9 mb/d in 2005.

In May 2001, Petrobras increased its five-year exploration and production expenditure by $600 million to $19.2 billion. At the same time, the company stated its target to cut lifting costs, excluding government take, from $3.70 per barrel in 2001 to $2.80 by 2005.

Table 2.22: **Petrobras Plans for Installation of Production Platforms**

Field	**Capacity (kb/d)**	**Arrival Date**	**Comment**
Roncador	90	September 2002	New platform
Barracuda	150	December 2002	
Caratinga	150	January 2003	Formerly December, 2002
Bijupira-Salema	18	2003	
Albacora Leste	180	2003	Formerly 2004
Roncador	90	2004	New platform
Frade	110	2005	Formerly 2003
Roncador	140	2005	Formerly 2004
New Production Capacity	928		

Source: Petrobras Company accounts.

Mexico

Overview

Assisted by high oil prices, Mexico's GDP grew by 7% during 2000, exceeding government forecasts. The oil-price windfall has also had a positive effect on Mexico's external accounts and fiscal revenues, but the economy has become more dependent on oil than it was a decade ago. During the presidency of Carlos Salinas (1988 to 1994), oil accounted for 29% of GDP. At the close of the Ernesto Zedillo presidency in 2000 it

89 Petrobras presentation, New York, 8 May 2001.

accounted for 35% of GDP. However, high oil prices have not contributed to higher investment in the oil sector, as most oil revenues go straight into the Treasury's coffers. For many years there has been insufficient capital investment in the upstream oil industry. The state-owned refineries and petrochemical plants are also in need of upgrading.[90]

Investment in Mexico's oil and gas sector fell by two thirds between 1981 and 2000. In March 2001, energy minister Ernesto Martens announced that investment requirements for the energy sector for the period 2000 to 2010 amount to $140 billion, of which $50billion will be for oil and gas exploration and production.[91]

Vincente Fox, elected as President in July 2000, has announced plans to restructure and modernise Mexican government and industry, especially the energy sector. Following nationalisation of the Mexican oil industry in 1938, *Petroleos Mexicanos* (Pemex) is the only company in the Mexican oil market. Although no foreign oil and gas operators have been allowed to participate in Mexico's upstream sector, foreign service companies were awarded contracts in March 2001 to drill and complete some 240 wells in the north-eastern Burgos basin.

Resources and Production

After Venezuela, Mexico has the second largest oil and NGL reserves in Latin America, at 22.3 billion barrels. The USGS estimates that Mexico has some 23 billion barrels of undiscovered recoverable resources of oil and NGL.[92]

Mexico accounted for 5% of total world oil production in 2000 and was the largest oil producer in Latin America. Mexico is the fourth-largest oil supplier to the US market, accounting for nearly 7% of US demand in 2000. The value of Mexican oil exports to the US in 2000 was estimated to be $10.4 billion. Mexican exports grew strongly in the 1970s and early 1980s with increasing production. (Figure 2.30).

Mexico produced some 3.5 mb/d in 2000 and is expected to increase production during the period to 2020. Three-quarters of current production comes from the Campeche Bay area in the Gulf of Mexico. Production increases over the next decade will be largely based on investments in enhancing production at existing fields. These investments

90. Comments by Raul Munoz Leos, Pemex director general, *Financial Times,* 28 August 2001.
91. Presentation by Ing. Ernesto Martens at the "Energy Business Forum for the Energy Hemispheric Initiative", Mexico City, 7 March 2001
92. USGS (2000).

centre on a nitrogen injection project to boost oil recovery in the Bay of Campeche and on a comprehensive program to boost production in the Delta del Grijalva region. Nitrogen injection is being used to offset declining production rates in the Cantarell fields in the Bay of Campeche. The goal of the project, involving development of the world's largest nitrogen plant, is to boost production in the Cantarell field from 1 mb/d to 1.8 mb/d in six years.[93] Nitrogen injection is also being considered to lift production in the Ku-Xzaap-Maloob complex. (Table 2.23).

Table 2.23: **Projected Production as a Result of Nitrogen Injection, Ku-Xzaap-Maloob Complex**

Calendar year	Daily production, thousand b/d	Annual production, million barrels
2001	300	110
2004	350	128
2009	460	168
2014	550	201
	Total	2,336

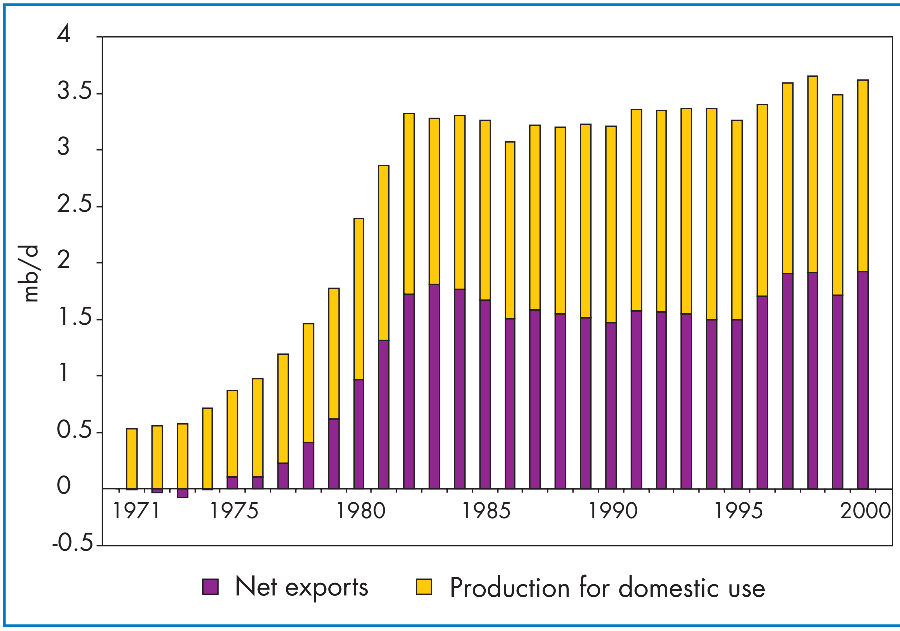
Source: *Oil and Gas Journal*, 7 May 2001.

An extensive field-development project in the coastal Tabasco Province is also underway. The Tabasco field is promising because of its high gas-to-oil ratio and the high quality of its light and ultra-light crude oils. To reach its production target of 110 kb/d, 24 new wells must be drilled and 12 new offshore platforms built by 2006.

The average total costs of supply for 2000 are estimated at $4.63 per barrel before tax. About two-thirds of this cost is for production with the remainder for finding and development. There are important regional differences in costs, with the lowest costs for offshore and the highest for the northern onshore.[94]

93. *Oil and Gas Journal*, 7 May 2001.
94. Communication with Secretaría de Energía, Mexico.

Figure 2.30: **Mexican Oil Production and Net Exports**



Source: IEA analysis.

Venezuela

Overview

The Venezuelan economy is heavily dependent on oil, which accounts for roughly three-quarters of its exports and about a third of GDP. In 1989, the Venezuelan government began to develop a policy known as *Apertura Petrolera* (Petroleum Opening) that encouraged foreign investment in its oil industry. The central goal of the policy was to increase Venezuela's productive capacity through the rejuvenation of its existing fields, the development of its huge resources of extra-heavy crude, and the discovery of new fields of medium and light crude outside the traditional producing regions. The first phase of this strategy opened up the operation of inactive or abandoned fields to the private sector.

Venezuela recently unveiled a draft Hydrocarbons Law. This law is intended to replace the *Medina Angarita* Hydrocarbons Law of 1943, that, coupled with the 1975 Nationalisation Law and several other pieces of legislation, now forms the backbone of energy policy in Venezuela. The new law, expected to be enacted late in 2001, will affect investment in the upstream oil and gas industry. Highlights of the draft include:

- proposal to increase royalties from 16.67% to 30%; to offset this increase, the tax on foreign operators' profits is likely to be lowered, from 67% now to possibly 34%; ratification of state control over Petróleos de Venezuela, S. A (PDVSA) and all its affiliates, current and future;
- responsibility for setting taxes to rest solely with the Energy and Mines Ministry, which answers directly to the President; this would eliminate taxes that oil companies now pay to municipalities;
- a provision requiring companies operating in the country to submit to whatever decision is taken by the government in international agreements or treaties; though it is not specifically stated, these agreements are expected to include OPEC production cut agreements; current law does not have such a requirement, although the operational agreements signed during the second and third *Apertura* licensing round did include clauses committing foreign oil operators to cuts.

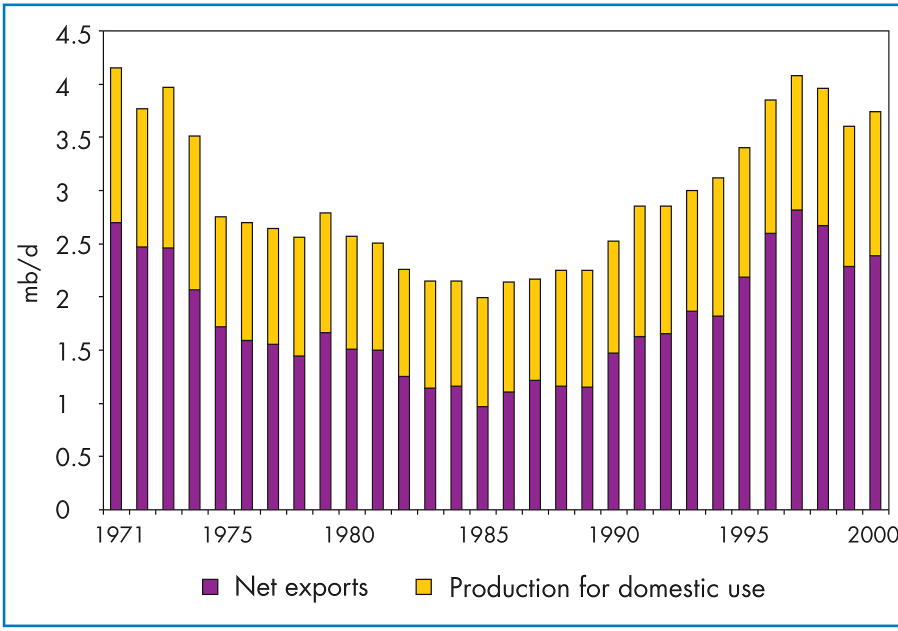
Resources and Production Outlook

According to the USGS 2000 assessment, Venezuela contains the largest oil and NGL reserves in Latin America, at 30.3 billion barrels. This compares with an estimate of 77 billion barrels by the OPEC Secretariat. The USGS estimates that Venezuela has some 24.2 billion barrels of recoverable resources of undiscovered oil and NGL.[95] Venezuelan oil accounted for 4% of total world oil production in 2000, and Venezuela was the world's fourth largest net oil exporter. The United States took 58% of Venezuelan net exports in 2000. Production has fallen recently because of OPEC restrictions on output.

Venezuela's current maximum sustainable production capacity is estimated at approximately 3 mb/d.[96] In its five-year plan released in February 2001, PDVSA, the state-owned oil company, said it plans to raise crude oil production capacity to 5.5 mb/d by 2006.[97] Some industry analysts consider this to be over-ambitious in view of the significant reductions in production resulting from OPEC quotas.

95. USGS (2000).
96. OPEC Secretariat.
97. PDVSA news release, 30 April 2001.

Figure 2.31: **Venezuelan Oil Production and Net Exports**



Source: IEA analysis.

Venezuela has four major sedimentary basins: Eastern, Western, Barinas-Apure and the largely unexplored Northern basin. Most of current production occurs in the Barinas-Apure region. PDVSA spends a large share of its budget on enhanced recovery techniques to maintain output levels, due to the maturity of many of these basins. Heavy crude oil accounts for some three-quarters of Venezuelan oil production. The largest extra-heavy oil reserves in the country are in the Orinoco oil belt in eastern Venezuela.

Heavy Oil and Orimulsion®

According to Bitor, a subsidiary of PDVSA, there are more than 1.2 trillion barrels of bitumen in the Orinoco Belt. Economically recoverable resources are estimated at about 267 billion barrels. After emulsification with water, the bitumen can be transported and subsequently burned in power plants. While it is priced to compete with coal, it has greenhouse-gas emissions similar to those of fuel oil.

Table 2.24: **Four Extra-Heavy Crude Upgrading Projects in Venezuela**

	Technical Leader	**Synthetic crude exports**			**Development cost**	
		Start date	(kb/d)	API gravity*	($ billion)	($/b/d)
Petrozuata	Conoco	February 2001	104	22	3.4	32,700
Cerro Negro	ExxonMobil	June 2001	105	16	1.6	15,240
Sincor	TotalFinaElf	January 2002	180	30-32	4.0	22,220
Hamaca	Phillips	May 2004	180	26	3.8	21,100
Total			569		12.8	22,500

*API gravity means the weight per unit volume of hydrocarbon liquids as measured by a system recommended by the American Petroleum Institute (API) and is expressed in degrees. It is defined as being equal to (141.5/Specific gravity) – 131.5. As a result, a hydrocarbon liquid with a specific gravity of 0.8251 or less will have an API gravity of 40 or higher. (American Petroleum Institute glossary and definitions)
Source: Petrostrategies.

Venezuela is also looking at capitalising on its extra-heavy oil reserves by transforming the extra-heavy oil into synthetic crude. Four projects are at different stages of development. Total investments of about $12.8 billion are expected to produce 569 kb/d of synthetic crude exports, at an average development cost of $22,500 per b/d. Venezuela expects that future projects can be carried out at a lower development cost. Future projects are estimated to cost $17,000 per b/d of synthetic crude. Extension projects could add a further 500,000 b/d of capacity before 2010 (Table 2.24).

CHAPTER 3
GLOBAL GAS SUPPLY OUTLOOK

Summary

The global gas market is poised for rapid growth

- The global market in natural gas is poised for continued rapid expansion thanks to its ample availability, its cost-competitiveness and its environmental advantages over other fuels. New power plants will provide the bulk of the incremental gas demand.
- Regional disparities in gas reserves and production costs are expected to lead to shifts in regional supply patterns. Output is expected to increase in the transition economies, OECD Europe and North America, but the shares of these regions in world production will decline because of faster growth in output elsewhere, notably Asia, the Middle East and Latin America.
- The principal factors behind these gas-supply projections are the size and distribution of reserves, supply costs, gas prices, government policies and new ways of trading gas, including the emergence of gas-to-gas competition.

Gas resources are abundant...

- Gas is an abundant energy source. Reserves were 164 tcm at the start of 2001, equal in energy terms to the world's total proven reserves of oil. As with oil, a few countries dominate the global picture for gas reserves; half of global gas reserves are found in two countries, Russia and Iran. Nonetheless, gas reserves are more evenly dispersed throughout the world than oil. The number of countries known to have significant reserves has risen from around 50 in 1970 to nearly 90 today. Remaining resources, including proven reserves, reserve growth and undiscovered resources, are estimated by the US Geological Survey at 386 tcm (mean) and by Cedigaz at 450-530 tcm. The latter estimate is equivalent to about 170-200 years of supply at current levels. Undiscovered gas resources total 147 tcm and reserve growth 104 tcm according to the USGS.

- Proven gas reserves have doubled over the past twenty years, outpacing oil reserves, in large part because gas reserves are being depleted more slowly than oil reserves. Strong growth in gas reserves has occurred in the FSU, Middle East and the Asia/Pacific region. Further discoveries will no doubt be made, but finding huge new fields in well-explored basins is unlikely. Exploration now leads increasingly to upward revisions of existing reserves and to smaller discoveries.
- Most of today's gas reserves were discovered in the course of exploration for oil. With higher gas prices and growing opportunities to market gas, international oil companies are increasingly interested in the search for gas *per se*. There is also a trend toward deeper-water exploration and development.

...but getting the gas to market will require massive investment

- Exploiting the world's gas resources will require massive investment in production facilities and infrastructure to transport gas from the regions with large and low-cost gas reserves to highly populated areas with growing gas demand. A lack of local markets has often impeded the development of gas reserves.
- The share of transportation in total supply costs in general is likely to rise as supply chains lengthen with the depletion of reserves located closest to markets. Pipelines will remain the principal means of transport for gas in North America, Europe and Latin America, but liquefied natural gas is likely to play a growing role. LNG trade is set to expand dramatically in the next two decades, mainly in the Asia/Pacific and Atlantic Basin regions.
- Gas prices, both in absolute terms and relative to oil prices and supply costs, will be the key driver of investment in gas projects. Wellhead prices higher than those that prevailed in the 1990s in most markets might be needed to elicit the necessary investment in supply infrastructure, as supply chains lengthen and costs rise. Nonetheless, there is scope for prices to fall from the peaks reached in late 2000 and early 2001.

Technology will be crucial in moderating supply costs

- Advanced technology, improved management practices and project design and productivity gains have reduced considerably the cost of finding and developing new gas fields and transporting gas to markets. Further advances in technology will be needed to reduce supply costs and open up new supply options.

- In the near term, the greatest potential for reducing upstream costs may lie in technology that improves identification of reservoir characteristics, such as seismic, as well as developments in drilling and production engineering. Significant potential also remains for reducing transportation costs through high-pressure pipeline technology, deepwater-pipeline systems, more efficient LNG plants and larger carriers.
- Costs may drop more slowly in the coming decade than in the last, if research budgets continue to decline. On the other hand, innovative technology may open up opportunities for exploiting resources that current technologies cannot tap. Continued advances in gas-to-liquids (GTL) technology could allow the development of some reserves currently considered to be "stranded" due to their small size and remoteness from markets. The amount of gas that is currently stranded is estimated at 49-65 tcm.

The impact of competition on investment is a key uncertainty

- The development of gas-to-gas competition, driven by regulatory reform, will have a major impact on prices and, therefore, on investment in upstream gas-supply projects. The spread of competition will stimulate the development of short-term (spot) markets and hasten the de-coupling of gas and oil prices in long-term contracts, although oil prices will continue to influence gas prices through inter-fuel competition. Long-term gas contracts will remain, but will tend to become shorter, with less onerous take-or-pay obligations.
- To the extent that competition results in lower prices at the wellhead and at borders, it could undermine some upstream developments. At the same time, however, competitive markets provide greater opportunities for producers to market their gas. By reducing transportation costs, competition may also allow for higher netbacks at the wellhead.
- In those countries with the longest experience of deregulated gas markets, competition has not yet undermined the development of gas reserves and supply infrastructure. But there are still concerns, especially in Europe, that competition could deter investment in large-scale, multi-billion dollar upstream supply projects. For such projects to proceed, long-term take-or-pay contracts will probably still be necessary, as well as close collaboration between upstream

and downstream companies and enhanced dialogue between the governments concerned to minimise investment risk.

Market growth and new supply chains will promote market integration

- Rising demand and expanding transportation networks will intensify market integration at the regional and global level. There are few physical connections now between the main regional markets. But these could increase with the prospect of rapid expansion in LNG trade. Prices in connected regional markets are likely to converge, depending on suppliers' ability to switch volumes between supply routes and markets.
- There are signs that the LNG market is becoming more flexible, as international trade grows and as downstream markets gradually open up to competition. Buyers are increasingly looking for short-term supply flexibility. In recent years, increasing volumes of LNG have been traded on the spot market, with trade flows changing in response to regional market factors.
- Continued growth in short-term LNG trading could spur a fundamental change in the way new LNG projects are structured. It may be possible in the future to finance gas-field developments and liquefaction projects without tying all the capacity to long-term contracts, as at present. This will happen if investors are confident that a fungible international market ensures full use of capacity. These changes could in turn lead to greater commercial opportunities for LNG projects to proceed, thereby enhancing the prospects for international trade.

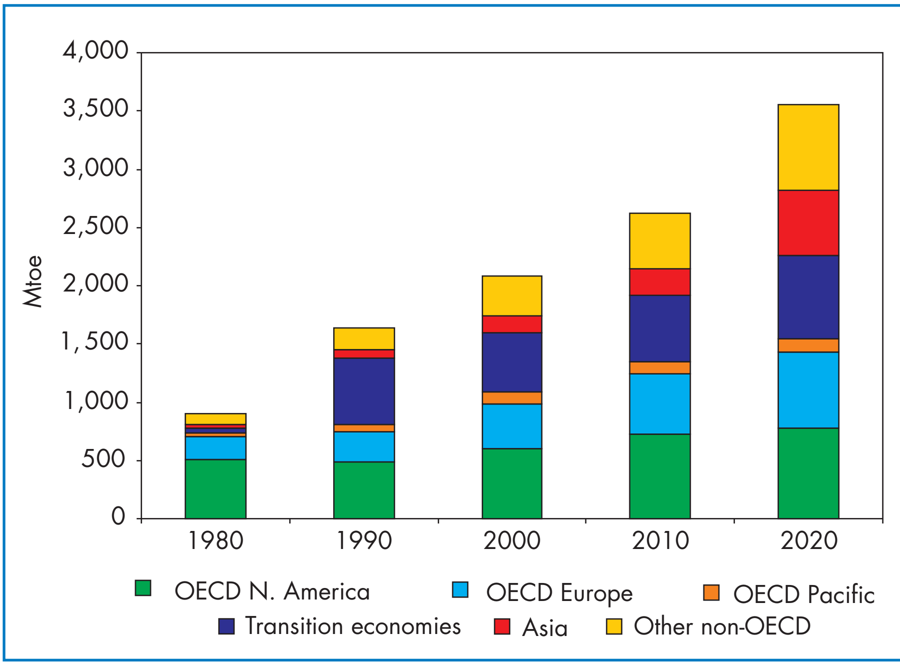
Overview of Gas Market Trends

Demand

Global demand for natural gas has grown much faster than for oil and coal over the past three decades, but still remains below them. In 2000, total world primary gas consumption reached 2.523 tcm – 22% of primary commercial energy use. OECD countries account for just over half of global gas demand and North America alone for over a quarter. The FSU, Eastern and Central Europe make up by far the largest gas consuming region outside the OECD. Power generation accounts for about 35% of primary gas use.

In the Reference Scenario of *WEO 2000*, world primary gas consumption is projected to continue growing steadily, by an average 2.7% a year from 1997 to 2020. This represents an increase of around 86%. Demand will be strongest outside the OECD, rising by 3.5% a year, while OECD consumption increases by 1.9% (Figure 3.1). Non-OECD countries' share of total demand reaches 56% by 2020, compared with 46% in 2000. Demand growth is particularly strong in non-OECD Asia. Gas use in the transition economies expands more slowly than in any other region, but these countries remain the second largest consuming region.

Figure 3.1: **World Primary Natural Gas Demand**



Source: IEA (2000a; 2001a).

In most regions, gas demand will grow primarily in response to the needs of power generation. Gas used by power plants increases at a rate of more than 4% a year, slightly faster than in 1971-1997. Electricity output from gas-fired plants increases even more rapidly because of continuing improvements in the thermal efficiency of combined cycle gas turbines. This factor, plus the inherent environmental advantages of gas over other fossil fuels mean that gas is often the preferred fuel in new power stations. In the OECD, power-sector gas demand increases most rapidly in Europe, reaching parity with North America by 2020. Among non-OECD countries, gas use in power plants grows most rapidly in absolute terms in Asia (as a whole), Latin America and the transition economies.

Final gas consumption grows at a more modest pace than primary gas use. Global industrial demand for gas rises by 2.2% a year, while residential/commercial demand grows by only 1.6%. Final gas use rises more slowly in the OECD regions due to saturation and the effects of a slowdown in population growth. Rising industrial output and commercial activity explain the more robust growth in developing countries.

As with any attempt to project energy demand, uncertainties surround these projections. The principal sources of uncertainty are:

- macroeconomic conditions, most importantly the rate of economic and population growth and changes in economic structure;
- gas prices, both in absolute terms and relative to other fuels, in part related to local gas availability;
- demand-side technological developments, especially the thermal efficiency of gas turbines;
- government policies, including those related to the environment and market liberalisation; tighter emission regulations could give a boost to gas, in view of its low carbon content and toxic emissions compared to other fossil fuels.

Regional Trends in Production and Trade

Gas reserves are not always located conveniently near centres of demand. Transportation is costly, whether by pipeline or in the form of LNG. Gas markets have, therefore, tended to develop on a regional basis, with demand being met primarily by local supplies. No global market for gas exists as yet, although regional market inter-connections and linkages are increasing.

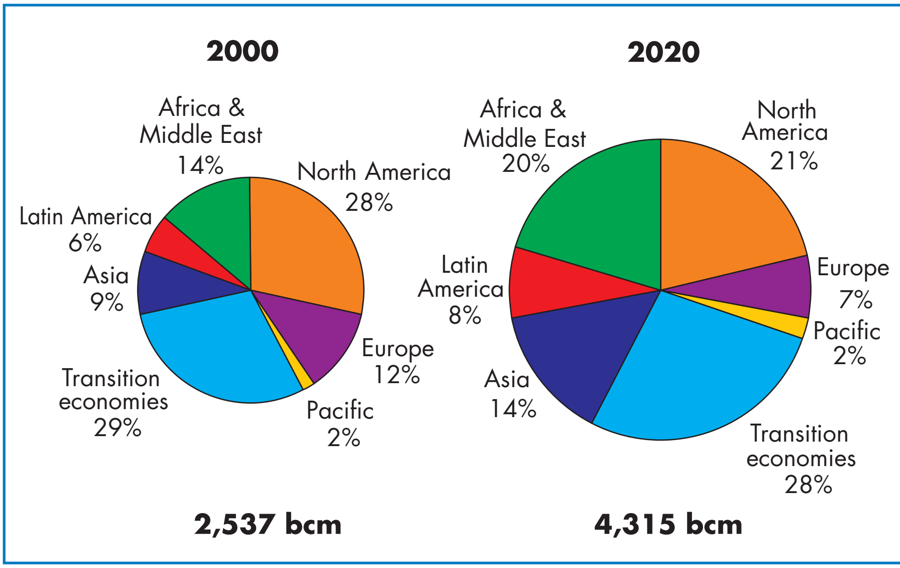
Box 3.1: **Principal Regional Gas Markets**

The main regional markets are:

- *North America*, including the United States and Canada (which together make up OECD North America) and Mexico. The gas supply infrastructure of the first two countries is highly integrated, while links between the United States and Mexico are limited but growing. Canada is a sizeable net exporter of gas to the United States.
- *Europe*, including OECD Europe and the transition economies. Russia is a major producer and net exporter of gas by pipeline to other transition economies and to the rest of Europe. Algeria is the other main external supplier, mainly to Southern Europe. The rest of OECD Europe's requirements are met by indigenous sources, mainly Norway, the United Kingdom and the Netherlands.
- *Asia/Pacific*, including Australia, Japan, Korea, China, Chinese Taipei, India and several Southeast Asia countries. Although geographically close, these markets are supplied separately and there are few physical links between them. Australia is self sufficient in gas, exporting surplus output in the form of LNG to Korea and Japan. China and India rely solely on indigenous gas. Korea and Japan import almost all their gas as LNG from Indonesia, Malaysia, Australia and the Middle East (Qatar, Oman and Abu Dhabi). Demand is developing and trade is taking off between Southeast Asian countries, notably Thailand, Malaysia, Myanmar, Singapore and Indonesia.
- *Latin America*, with demand centred on Argentina, Venezuela, Chile and Brazil. Argentina and Bolivia are the main exporters, to Chile and Brazil.

WEO 2000 set out projections of gas production and trade on a regional basis corresponding to projected demand in the Reference Scenario. Figure 3.2 compares current and projected regional shares in gas production. Table 3.2 details production trends in a more disaggregated way.

Figure 3.2: **Gas Production by Region**



Source: IEA (2000a,2001a).

Globally, gas resources are expected to be more than sufficient to meet the projected increase in demand until 2020, although regional disparities in reserves and production costs will lead to shifts in regional supply patterns[1]. Output will increase in the transition economies, OECD Europe and North America, but their shares in world production will decline because of faster growth in output elsewhere, notably in Asia, the Middle East and Latin America. The transition economies are nonetheless projected to account for the largest increase in output in absolute terms. The fastest rates of production growth are expected to occur in Africa and the Middle East, especially after 2010. These regions' combined share in world production is projected to increase from 14% in 2000 to 20% in 2020.

These projections imply a considerable expansion of inter-regional and intra-regional trade. Figure 3.3 illustrates the expansion in gas exports and imports in each major region. OECD Europe becomes increasingly dependent on imports of gas, mainly from the transition economies and

1. It should be noted that these production projections are based on assumptions concerning the growth in reserves as a function of the resource base and gas prices. Production projections at the regional level are inherently subject to uncertainty.

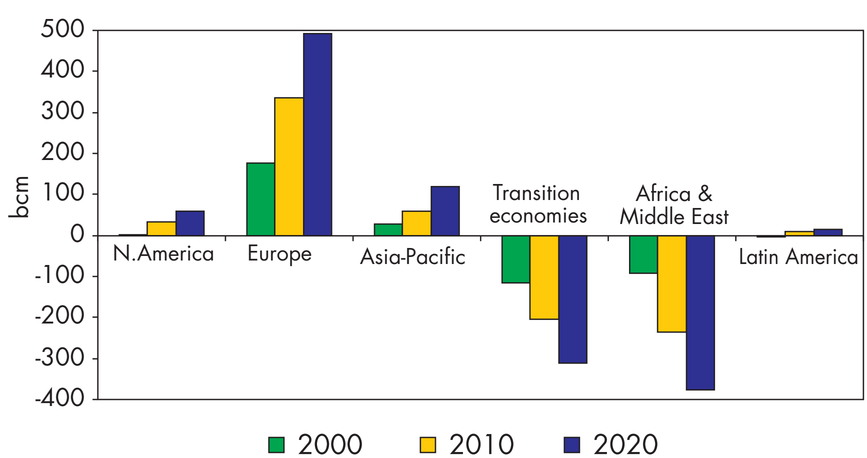
Table 3.2: **Gas Production by Region**

	bcm				% share of world total			
	1990	**2000**	**2010**	**2020**	**1999**	**2000**	**2010**	**2020**
North America	617	729	841	887	30	29	25	21
Europe	210	301	297	297	10	12	9	7
Pacific	27	40	70	92	1	2	2	2
Transition economies	835	738	898	1,177	40	29	27	28
of which Russia	640	584	697	849	31	23	21	20
Asia	124	232	387	615	6	9	12	14
Latin America	112	120	241	365	5	6	7	8
Africa	70	131	236	357	3	5	7	8
Middle East	99	223	340	524	5	9	10	12
World	**2,070**	**2,537**	**3,310**	**4,315**	100	100	100	100

Source: IEA (2000a; 2001a).

Africa, as demand increases and indigenous production remains flat. The rate of import dependence doubles to over 60% by 2020. OECD North America remains largely self-sufficient, but imports by pipeline from Mexico and imports from other regions in the form of LNG will make a growing contribution to supply. The dependence of OECD Pacific on gas imports from outside the region falls, as rising Australian production

Figure 3.3: **Natural Gas Net Imports**



Note: Exports are negative. International trade within regions, not reflected in this chart, is also significant.
Source: IEA (2000a; 2001a).

offsets the growing need for imported gas in Japan. Asia, currently a net exporting region, is projected to become a net importer in the second half of the projection period, supplied mainly from Australia, the Middle East and the transition economies.

As with demand, these supply projections are based on a range of assumptions, which are subject to uncertainty. The way in which the projected increases in demand are met at the regional level could turn out to be very different, depending on several factors. The most important of these supply-side factors and the main sources of risk to the projections are:

- the location, size and cost of extracting reserves; the projections are based primarily on resource estimates derived from the US Geological Survey;
- the cost of transporting gas to each market, including transit; there are considerable uncertainties about pipeline and LNG cost developments;
- policy considerations, including the perceived geopolitical risk and strategic implications of certain supply routes, supply diversity and environmental concerns;
- the price of gas in absolute terms and relative to that of oil; the higher the price, the greater the return on investment;
- developments in the structure of gas markets; competition is assumed to continue to develop throughout the world, mitigating to some degree upward pressures on costs.

Key Factors Affecting Gas Supply Prospects

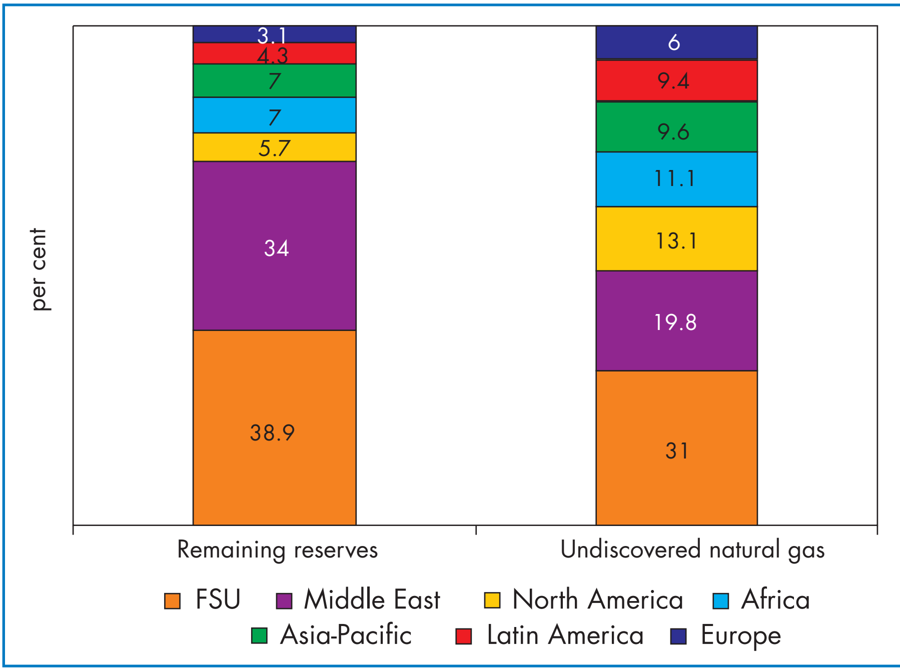
Gas Resources and Reserves[2]

Conventional Natural Gas Resources

The most widely used source of data for undiscovered gas resources is the U.S. Geological Survey (USGS) *World Petroleum Assessment,* which estimates the quantities of conventional oil, gas, and natural gas liquids. The most recent assessment, in 2000, confirms the huge potential of natural gas around the world.

2. There are three major sources of data on gas reserves and resources: the US Geological Survey (USGS), Cedigaz (an international centre for gas information) and the World Energy Council. They use different definitions and methodologies, which make comparisons difficult. Chapter 2 provides definitions of the different categories of reserves and resources.

Figure 3.4: **World Natural Gas Reserves and Undiscovered Resources by Region**



Source: USGS (2000).

The key findings of the 2000 USGS assessment are:

- Cumulative gas production since gas production started amounted to 49.6 tcm up to the end of 1995. Remaining gas reserves were estimated at 135.7 tcm as of 1 January 1996.[3]
- Much gas remains to be discovered. Undiscovered gas resources are estimated at 147.1 tcm, of which 25% are associated with oil and 75% non-associated gas.
- The largest known gas accumulations are in Western Siberia and the Persian Gulf. Over two-thirds of the world's proven gas reserves are in the FSU and the Middle East, with only 6% in North America. However, the situation is markedly different when ultimate resources are considered. Of them, 13% are in North America with just over half in the FSU and the Middle East.

3. Cedigaz estimates cumulative gas production up to the end of 2000 at 70.4 tcm and remaining reserves at 164 tcm at 1 January 2001.

- Compared to the previous USGS assessment in 1995, undiscovered volumes in this assessment (not including the United States) are 14% smaller. This is due to lower estimates for arctic areas of Russia, some basins in China, and the Alberta Basin in Canada. In some countries, however, major upward reassessments were made. For instance, undiscovered volumes in Brazil are now estimated at 5.5 tcm (mean), six times the previous estimate. Major upward reassessments were also made for Australia and Indonesia.
- Areas that contain the greatest volumes of undiscovered conventional gas include the West Siberia Basin, the Barents and Kara Seas shelves of the FSU, the Middle East and offshore in the Norwegian Sea. In a number of areas, large discoveries have been made but remain undeveloped. These include East Siberia and the Northwest Shelf of Australia (where development is now underway).
- Potential reserve growth is estimated at 103.6 tcm. This is nearly as large as estimated undiscovered resources. These estimates imply that 66% of the growth in conventional gas resources has already been discovered (excluding the United States).
- Only slightly more than 10% of world gas resources have been produced, compared with almost 25% of estimated world oil resources.

Table 3.4: **USGS Global Natural Gas Resource Estimates** (tcm)

	Range	Mean
Cumulative production		49.6*
Remaining reserves		135.7
Reserve growth		103.6
Undiscovered conventional gas	76.2 – 251.2	147.1
Total	**365.1 – 540.1**	**436.0**

* Actual
Source: USGS (2000).

Cedigaz estimates ultimate remaining gas resources at 450-530 tcm. This global estimate is a bit higher than the USGS mean figure. The difference is due to the adoption by USGS of a 30-year forecast period instead of the unlimited forecast span used by Cedigaz. It is not possible to

Table 3.5: **Cedigaz Estimates of Reserves and Resources**
(tcm, as of 1 January 2000)

	Cumulative production	Proven reserves	Ultimate resources Remaining	Ultimate resources Initial
North America	28.3 (29.0)	6.2 (6.6)	27-34	55-62
Latin America	3.5 (3.6)	7.7 (8.2)	22-27	25-30
Europe	7.7 (8.1)	7.6 (8.2)	13-16	20-23
FSU	17.8 (18.5)	56.9 (55.8)	222-250	240-270
Africa	2.3 (2.4)	11.0 (11.7)	23-28	25-30
Middle East	4.4 (4.6)	53.9 (58.5)	115-136	120-140
Asia	3.9 (4.2)	14.8 (15)	31-36	35-40
World Total	67.9 (70.4)	158.1 (164)	453-527	520-595

Note: Figures in brackets show data at 1 January 2001. Ultimate resources include proven reserves.
Source: Cedigaz (2001)

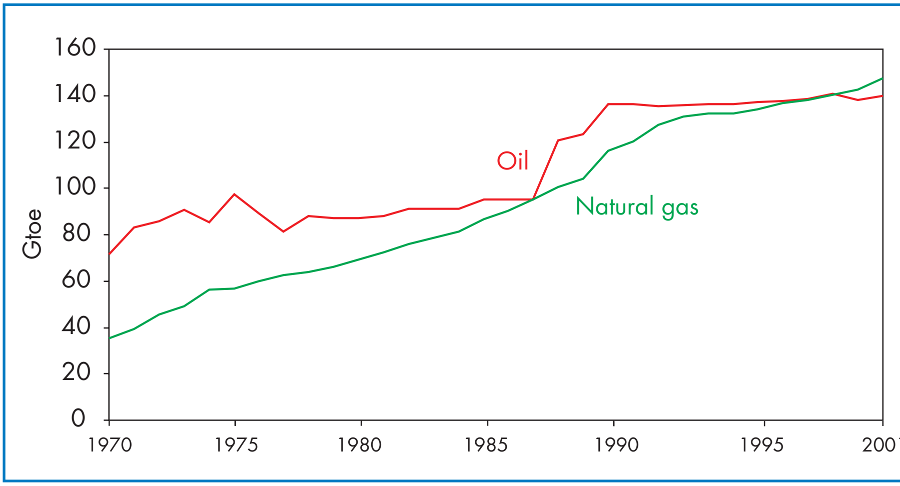
make a regional comparison with USGS data since the USGS estimates reserve growth only at the worldwide level.

Proven Conventional Natural Gas Reserves

Steady successes in gas exploration over the past few decades have led to continuous upward revisions of worldwide proven reserves. In fact, reserves have doubled over the past 20 years (Figure 3.5). At 1 January 2001, they were estimated at 163.9 tcm by Cedigaz, the source of data used in this section and the most widely used for proven reserves. The increase in proven reserves is due not only to sustained exploration and appraisal activity in all areas of the world but also to developments in technology that have allowed existing reserves to be upgraded. Natural gas reserves were only half as large as oil reserves in 1970 and 80% as large in 1980. They now exceed oil reserves by 5% in energy-equivalent terms. They total 147.5 Gtoe, compared with 140.8 Gtoe for oil reserves. Oil reserves have grown more slowly than gas largely because oil reserves are being depleted more rapidly.

While two countries, Russia and Iran, hold 50% of global gas reserves, gas reserves are nonetheless more widely distributed among regions than are oil. The FSU holds 36% of the global reserves, but its share has decreased steadily over the past decade, as a result of low exploration activity in Russia. Around 36% of world gas reserves are found in the Middle East and its share is growing as major discoveries and expansions of existing fields are made in the region, especially in Iran, Saudi Arabia and

Figure 3.5: **Proven Global Reserves of Natural Gas and Oil**



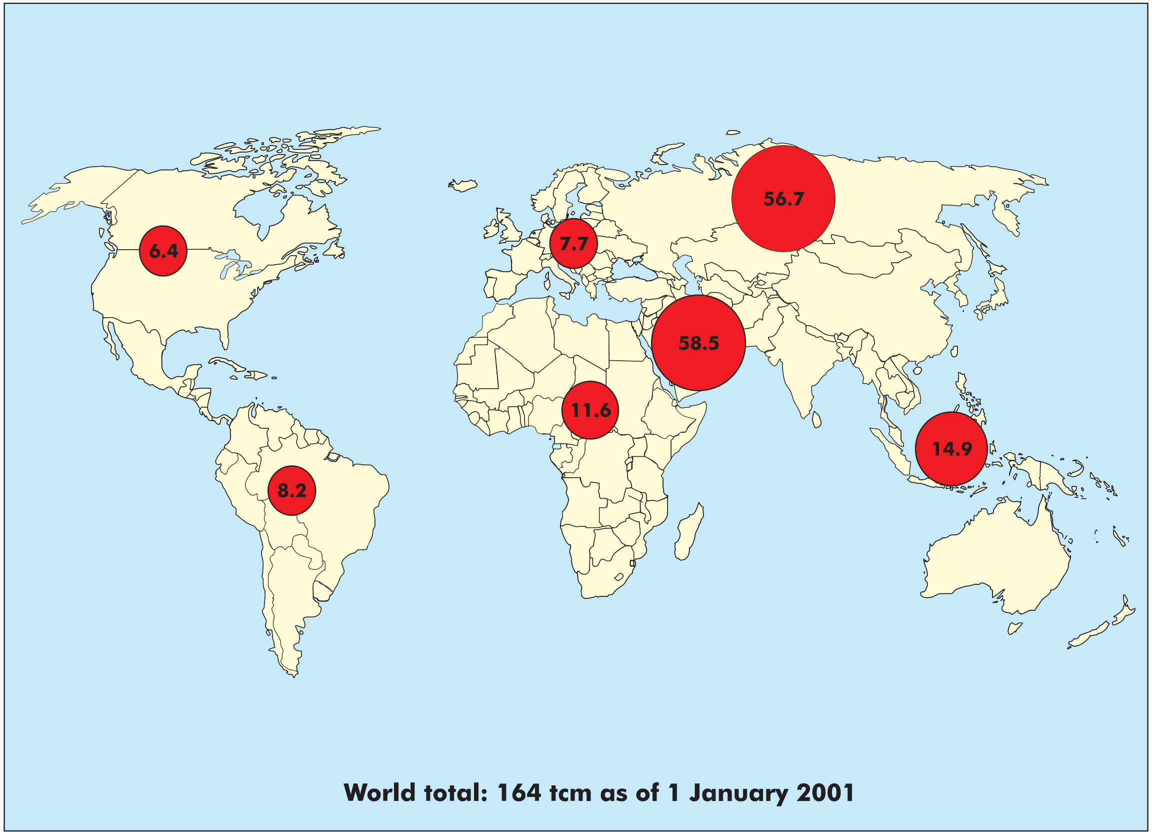
Note: 1,000 cm of natural gas = 0.9 toe.
Source: Cedigaz (2001).

Qatar. OECD gas reserves are estimated at 18.4 tcm, or 11.2% of the world total. While the OECD share in global reserves is shrinking slowly, it still represents 17 years of current OECD production.

The ratio of global reserves to production (R/P) is 60 years of production at present rates compared to less than 40 years for oil reserves. R/P ratios exceed 200 years for the Middle East and are very high for the FSU (about 74 years), OECD Pacific (80 years) and Africa (67 years). The R/P ratio for Latin America is also high (45 years), compared with only 8 years for North America and about 23 years for OECD Europe. R/P ratios have generally declined in recent years (Figure 3.7).

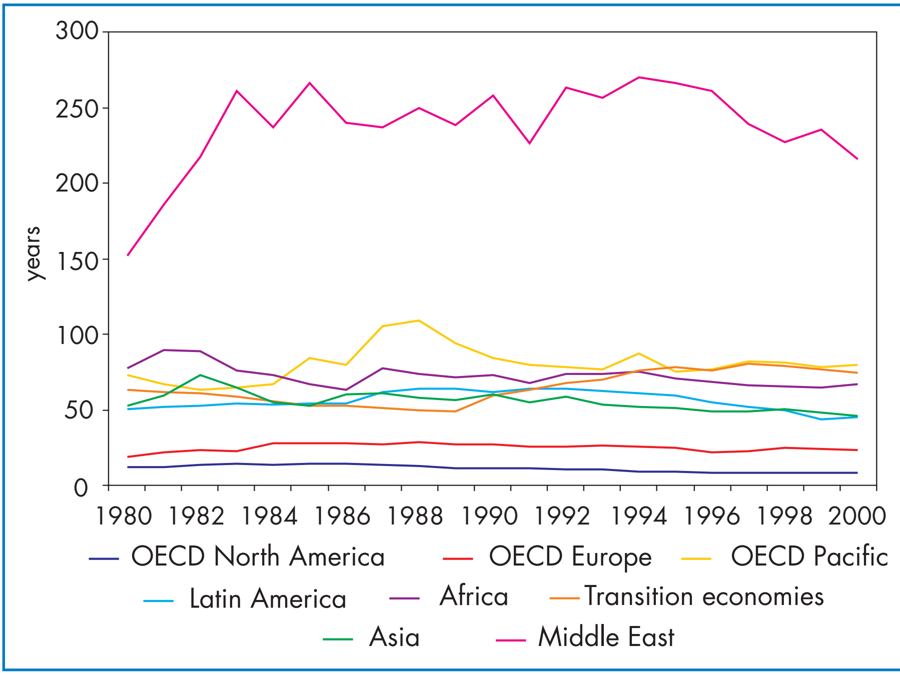
In the past ten years, major advances have occurred in 3D seismic-based exploration, drilling efficiency and well-simulation technology. These have significantly increased reserves per well, drilling success, and recoverable gas resources. These advances have been achieved through an improved understanding of the fundamental geological and reservoir properties that determine gas-production rates, particularly from more complex reservoirs. Exploration and production companies are continuing to develop and deploy new technology, often in partnership with governments.

Figure 3.6: **Global Natural Gas Reserves**



Source: Cedigaz (2001).

Figure 3.7: **Reserves to Production* Ratio by Major Region**



* Gross production less re-injection.
Source: Cedigaz (2001).

Box 3.2: **Major Recent Discoveries**

The numerous gas discoveries made recently confirm the abundance of this resource and demonstrate the growing emphasis on gas exploration. Most of the biggest discoveries in recent years have been made in the Middle East. In Iran, five new gas and gas/condensate reservoirs have been discovered (Ghareh-Dorgh, 600 bcm; Tabnak, 400 bcm; Homa, 200 bcm; Ramhormoz, 40 bcm and Zireh, 24 bcm). The Al-Ghazal and Al-Manjura structures have been discovered in Saudi Arabia. Interesting finds have also been made in Israel. Qatar has revised its estimate of North Field reserves upward, to 14.15 tcm.

In Egypt, eleven gas discoveries were made from July 1999 to the end of 2000, and reserves were revised upward to 1.44 tcm. In September 2000 alone, four gas discoveries were reported, with gas reserves of 170 bcm, equivalent to 11 years of Egyptian consumption at current levels. Exploration wells drilled in Algeria have also yielded fruitful results.

In Latin America, Trinidad and Tobago has registered major new discoveries. Bolivia has continued to upgrade the reserves of the San Alberto and Itau structures; their potential is now estimated to be greater than that of the Peruvian Camisea field, which contains 340 bcm.

In Asia, major discoveries have been made in Indonesia (Makussar Strait and Natuna Sea and Timor Sea). Discoveries in the transition economies include the Shah Deniz field in Azerbaijan.

Gas Reserves by Type

Although proven reserves are abundant, new resources tend to be discovered farther and farther away from consuming areas, in more difficult terrain or in small marginal fields. Operating conditions are worsening and natural gas is becoming more expensive to produce and transport.

Remote Gas

The geographical distribution of natural gas reserves around the globe is not ideal. Most demand is concentrated in North America and Europe. But these regions are relatively poor in gas, partly because they have depleted a large proportion of their initial reserves. The FSU and the Middle East account for 70% of the world's proven reserves. Latin America, North America and Europe each account for only 5%. Large gas reserves located in North Siberia, and a big share of Middle Eastern and African fields have to be considered too remote from consuming centres to be exploited at the price levels of recent years. Roughly 15 to 25% of global gas reserves (24 to 40 tcm) can be considered remote. However, estimates of "remote" gas are very sensitive to transportation costs. Innovative technology will be an essential factor in commercialising such reserves.

Frontier Gas

A growing share of untapped gas reserves and of new gas being discovered is in areas where access is difficult due to terrain or climate. So-called "frontier gas" now accounts for over half of proven reserves. From 1970 to 1990, about 70% of the net additions of reserves were discoveries made in difficult zones, such as arctic Siberia, or in deep offshore areas in the Gulf of Mexico.

The potential of deepwater-hydrocarbon development is enormous. Deep offshore reserves are currently estimated at around 8 tcm, about 15% of total offshore-gas reserves and 5% of total world reserves. Development of these resources will be of growing importance to the gas supply outlook. In the Gulf of Mexico, new technology has allowed Shell to produce gas in 1,650 metres of water in the Mississippi Canyon Mensa. TotalFinaElf is also testing ultra deep-water production there with its Aconcagua prospect, at a water depth of 2,155 metres.

Field Size

Gas reserves are concentrated in a very small number of giant accumulations. Some 190 giant reservoirs account for 57% of initial global gas reserves. Slightly fewer than 25,000 small fields hold only 28% of world reserves; 15% are in "marginal" fields with less than 10 bcm. About 80% of these small reservoirs are in North America. In Western Europe, most marginal fields are in the United Kingdom.

In North America, an extensive network infrastructure and open access make commercial exploitation of marginal fields possible, provided the gas price is high enough. New offshore infrastructure development may make fields now considered "marginal" economic in the North Sea.

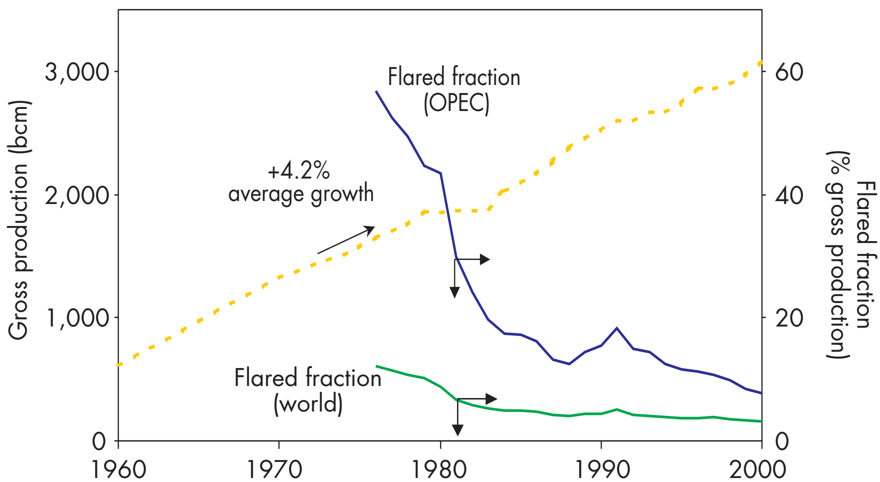
Associated Gas

A large share of gas reserves are in associated oil and gas fields. "Associated gas" now accounts for about 25% of global gas reserves (39 tcm), most of it in the Middle East (21.6 tcm or 40% of Middle Eastern proven reserves), in Africa (5.8 tcm or 52% of reserves) and in Latin America (4.3 tcm or 56% of reserves). Producing oil is usually much more profitable than producing gas. The gas contained with oil reservoirs is often regarded as a by-product or a cost factor. It is either flared or reinjected to enhance oil recovery. When circumstances allow, it is processed, transported and sold.

In Saudi Arabia and Venezuela, where the share of associated gas in total reserves is high, OPEC production quotas on crude oil directly affect the availability of associated gas. These constraints are encouraging the search for non-associated gas resources.

The flaring of associated gas, which was common in the 1970s, has fallen off considerably. Nigeria is implementing a programme to eliminate flaring completely by 2008. Nonetheless, 96 bcm of gas was flared in 2000,

Figure 3.8: **Evolution of Flaring of Gas**



Source: Cedigaz (2001).

half of it in OPEC countries. When no infrastructure for transmission and distribution is available, there are only a limited number of outlets for associated gas. To avoid flaring and to enhance the recovery of oil, Iran, Abu Dhabi, Algeria, Venezuela and Norway have implemented ambitious re-injection programmes. Global gas re-injection has been growing steadily, reaching 354 bcm in 2000.

Gas Quality

The quality of natural gas resources is becoming an increasingly important issue. It substantially affects the economics of gas-supply projects. About 35% of world gas reserves are "wet"; 30% of this wet gas is "sour". Wet gas contains natural gas liquids, hydrocarbons heavier than methane, which need to be extracted. This can make field development more costly, but in many cases, the commercialisation of NGLs can enhance the profitability of the total project. This is the case at the Troll field in Norway and at the North Field in Qatar.

"Sour" gas is natural gas that contains sulphur, sulphur compounds and/or carbon dioxide that may require removal for the commercial use of the gas. In many cases, sour gas is too costly to be produced at present prices. In Indonesia, the development of the huge Natuna field, discovered in 1973, has been delayed by its high CO_2 contents and the need to process the gas and store the CO_2. New and improved treatment process designs to remove sour gas components (sequestration of CO_2) are likely to be developed.

Estimates of "Stranded" Gas

A large part of proven reserves is "stranded". This term covers: reserves remote from consuming areas; reserves in very remote offshore reservoirs in very inaccessible places like the Arctic; reserves in very small fields; and associated gas that is flared or re-injected for oil recovery. The production and transport costs for such gas may be too high for it to be extracted and marketed profitably.

The definition of stranded gas depends on technical and economic factors. A large share of today's "stranded" gas may become economically viable in the future with technological advances and cost reductions along the gas chain. Similarly, gas that is now re-injected may become saleable in the future. Cedigaz estimates the world's stranded gas at about 49-65 tcm. It represents a huge potential for energy consumption if it can be commercialised. According to a study of 1,426 fields in 225 basins in 63 non-OECD countries by Petroconsultants and Zeus[4], the potential of stranded gas is 25 tcm.

Commercialising these reserves will depend on further reductions in the cost of exploration, production and transportation, reduced flaring of associated gas and new uses for these reserves, such as GTLs. Market prices will also need to be high enough and the regulatory and investment framework sufficiently attractive to attract the required investment. The Zeus/Petroconsultants' study shows that there are significant stranded gas

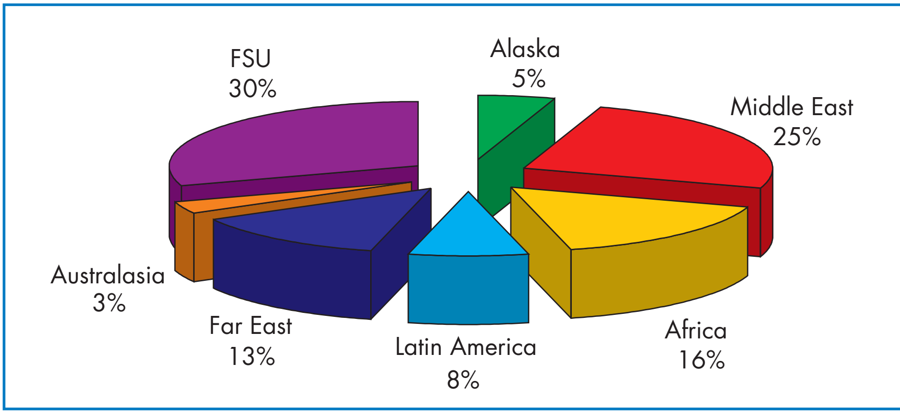
Table 3.6: **Global Stranded Gas Potential** (tcm, as of 1 January 2000)

Associated gas	12
Deep offshore	8
Marginal fields	5
Remote fields	24-40
Total	**49-65**

Source: Cedigaz (2001).

4. Zeus Development Corporation and Petroconsultants-MAI (1999).

Figure 3.9: **Estimate of Stranded Gas by Region**



Source: Zeus Development Corporation/Petroconsultants-MAI (1999).

reserves around the world that could be produced for less than 25 cents/Mbtu.

Prospects for Unconventional Gas

The distinction between conventional gas and unconventional gas is not well defined, because they are found in a continuum of geologic conditions. "Unconventional gas" refers mainly to gas extracted from coalbeds (coalbed methane) and from low-permeability sandstone (tight sands) and shale formations (gas shales). Gas from tight sands and shales requires special treatment for recovery. Gas hydrates may also be considered an unconventional source, although the technology to produce gas from hydrates does not yet exist.

Unconventional gas – mostly coalbed methane (CBM) and tight gas – has become an important component of total US domestic production over the past decade, accounting for 25% of total gas production in 1999, up from only 18% in 1990. In the rest of the world, unconventional gas production is modest. Although unconventional gas resources are abundant, they are generally costly to produce. The exploitation of CBM in the United States was boosted in the late 1980s and early 1990s by tax incentives. Technically recoverable unconventional resources in the United States are substantial.

According to a 1995 USGS survey, such resources range between 6.2 tcm and 11.8 tcm, with a mean of 8.7 tcm.[5] Little assessment has been done in other countries.

5. USGS (1995).

Expanding our understanding of unconventional resources, developing new exploration methods, improving recovery efficiency and lowering drilling and well-completion costs will be important factors in the future production of unconventional resources. According to the US Energy Information Administration, technological progress can stimulate continued near-term growth of US unconventional gas production and sustain its long-term contribution at about 225-280 bcm per year. There is much more impetus for the development of unconventional gas in the United States than in the Middle East, where conventional gas reserves are expected to last hundreds of years.

Coalbed Methane

Large amounts of methane-rich gas are stored in coalbeds. The USGS estimates worldwide resources in-place at up to 210 tcm, but this number is uncertain because of the scarcity of basic data on coal resources and gas content. The largest resources are in Russia, China, Canada, Australia, and the United States, but there are also significant resources in Germany, Poland, the United Kingdom, Ukraine, Kazakhstan, India and Southern Africa. Recoverability as well as the size of resources is a key factor for production prospects. The United States is the only country where commercial production of CBM currently takes place.

Tight Gas Shales and Sands

Large gas accumulations are sometimes present in low-permeability (tight) sandstones, shales and other reservoir rocks. They often contain a large amount of gas, but recovery rates are low. Gas can be economically recovered from better-quality continuous tight reservoirs by fraccing with explosives or hydraulic pumping. Such gas deposits are commonly classified as unconventional because their reservoir characteristics differ from conventional reservoirs and they require stimulation to be produced economically.

Tight gas resources are immense. However, there are many uncertainties about development costs and production technology. US unconventional gas from tight sandstone reservoirs accounts for 1 tcm of proven reserves and 8.1 tcm of undeveloped resources. Proven reserves of gas from fractured shale reservoirs in the United States amount to around 140 bcm and total resources to around 1.6 tcm. In 1999, 83 bcm of gas was produced there from 42 tight gas reservoirs.

Supply Costs

Gas Exploration, Development and Production

As with oil, advanced technology, improved management practices and project design and productivity gains have helped to reduce considerably the cost of finding and developing new gas fields and have opened up new areas to drilling in recent years. Technological developments include:

- 3-D and 4-D seismic techniques, which have improved drilling success rates;
- better drill bits and new drilling techniques, including horizontal drilling, which have greatly reduced development and production costs;
- new rig designs, which have made it feasible to drill in deepwater offshore areas that had been inaccessible.

Quantifying these cost reductions is difficult, partly because they are site-specific. The Energy Information Administration estimates that improved technology in the United States has increased drilling success rates by as much as 50% over the last 15 years.[6] A recent study for the European Commission found that new technology added 566 billion cubic metres (around 9%) to reserves on the Northwest European Continental Shelf over the period 1990 to 1997 by reducing costs.[7] Of this increase, advanced drilling technology is estimated to have contributed 37%, seismic technology 22%, floating platforms 10% and management cost reductions 7%.

There probably remains scope for further reducing the cost of gas exploration and production through the application of new technology as well as more efficient use of existing upstream infrastructure. In the near term, the greatest potential may lie in technology that improves identification of reservoir characteristics, such as seismic, as well as developments in drilling and production engineering. Research and development will be crucial here. The production of associated oil and NGLs will be a key factor in cutting costs in many instances. The rate of decline in costs, however, may slow down as the scope for technological advances and productivity gains narrows.

6. EIA (2001).
7. Commission of the European Communities (1999).

Gas Transportation

Economics of Pipeline and LNG Transportation

Gas can be transported in bulk either by pipeline or by sea-borne tankers as liquefied natural gas (LNG). Both methods require large, upfront construction costs. Both involve important economies of scale. Long-distance projects, therefore, require both large, high-value markets and substantial proven reserves to be economically viable.

Capital charges typically make up at least 90% of the cost of transmission pipelines. The key determinants of pipeline construction costs are diameter, operating pressures, distance and terrain. Capacity is a function of both diameter and pressure. Other factors, including climate, labour costs, the degree of competition among contracting companies, safety regulations, population density and rights of way, may cause construction costs to vary significantly from one region to another. Table 3.7 shows average capital costs per mile of the different cost components of pipelines (not including compressors) of different diameters and cost ranges in the United States. Average costs have more than doubled over the past ten years, mainly due to rising labour costs, which is the largest single cost element in most projects. The range of costs is very wide due to project-specific factors. Overall construction costs would be much lower in countries where rights-of-way and labour are cheaper.

Pipeline operating costs vary mainly according to the number of compressor stations, which require significant amounts of fuel, and local economic conditions, especially labour costs. In designing a pipeline, the optimal mix of diameter and compression capacity will depend on the expected load factor. Once a pipeline is built, the average cost per unit of throughput will depend almost entirely on the average rate of capacity utilisation. A high level of utilisation with a high load factor is usually critical to the economic viability of the pipeline.

An LNG supply chain includes liquefaction, shipping, regasification and storage. As in the case of pipelines, economies of scale are very significant:

- *Liquefaction* plants typically consist of one or two processing trains. The economic size of each train is now about 3 to 3.5 million tonnes per year. Adding a second train once a plant is built can reduce the overall unit cost of liquefaction by 20 to 30%. A single-train plant normally costs around $1 billion, although actual costs vary geographically according to land costs, environmental and

Table 3.7: **Average Gas Pipeline Construction Costs in North America, 2000**
($/mile)

Diameter (inches)	Average cost: Rights-of-way	Material	Labour	Other	Total	Total cost range (low-high)
8	20,099	51,065	385,845	137,789	594,797	90,727 – 4,003,300
12	30,721	83,069	264,461	163,653	541,894	190,731 – 885,051
16	132,500	121,675	374,154	359,815	988,143	241,877 – 3,612,208
20	175,788	227,202	506,423	318,035	1,227,447	548,727 – 1,928,926
24	119,147	238,555	461,141	327,696	1,146,538	402,515 – 2,168,000
30	138,324	389,249	639,270	463,670	1,630,514	985,036 – 4,457,536
36	195,848	454,764	779,527	442,122	1,874,260	1,256,079 – 10,708,278

Source: *Oil and Gas Journal* (4 September 2000).
Note: Based on FERC (US) and NEB (Canada) construction-permit applications for the 12-month period to 30 June 2000.

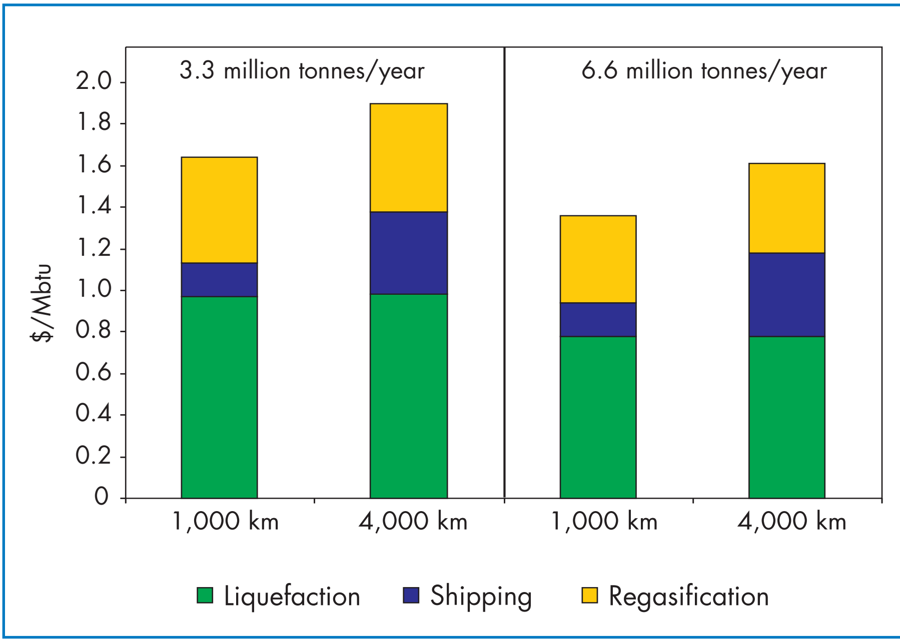
safety regulations, labour costs and other local market conditions. Operating costs, mostly fuel (equivalent to around 9% of throughput in new plants) and maintenance, depend on the cost of fuel and local labour costs but usually amount to less than 5% of total annualised capital expenditure.

- *Transport* costs are largely a function of the distance between the liquefaction and regasification terminals and the size of the vessel. Using a larger number of smaller carriers offers more flexibility and reduced storage requirements but raises unit shipping costs. The largest LNG carriers today have a maximum capacity of 135,000-138,000 cubic metres. They cost around $180 million to build. The largest vessels are used on long-distance routes, such as from the Middle East to Japan and Korea. Smaller ships, with capacities of 25,000-50,000 cubic metres are used on cross-Mediterranean routes. Operating costs include fuel in the form of boil-off (typically 0.15% to 0.2% of load per 1,000 km) and bunker fuel, as well as maintenance, which can amount to 3% to 4% of the purchase cost of the carrier (from $5 to $7 million for a 135,000 cubic metre ship).
- *Regasification* plant construction costs depend on throughput capacity, land development and labour costs (which vary considerably according to location), and storage capacity. Economies of scale are most significant for storage. These are maximised for storage tank capacities of about 150,000 cubic metres – the largest feasible at present.

LNG costs vary considerably in practice, largely as a function of capacity, particularly the number of trains in liquefaction plants and shipping distance. Figure 3.10 gives the cost breakdown for two different sizes of LNG project and for two distances based on indicative capital and operating cost estimates. For a standard two-train LNG chain with a capacity of 6.6 million tones per year and a transportation distance of 4,000 km, liquefaction accounts for around half the total cost and shipping and regasification each for about 25%. The unit cost of a two-train plant is typically about around 20% less than that of a one-train plant. However, market fragmentation and difficulties in securing long-term sales contracts to cover large volumes of gas can favour single-train projects.

In determining the most economic transportation method for a given supply route, distance is the key factor. Figure 3.11 compares pipeline and LNG costs according to pipeline diameter, size of LNG project and

Figure 3.10: **Breakdown of Indicative Levelised Annual LNG Costs**



Note: Calculations assume a 10% real discount rate and a 30-year project life. Capacities are for liquefaction. Unit costs are based on final regasified volumes.
Source: IEA analysis.

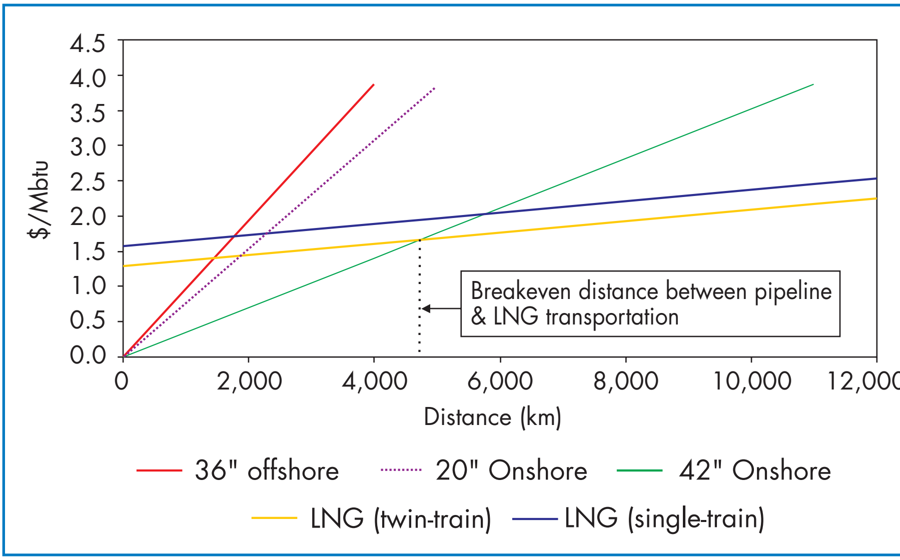
distance. For short distances, pipelines – where feasible – are usually more economic. LNG is more competitive for long distance routes, since overall costs are less affected by distance. The normal breakeven distance for a single-train LNG project against a 42” onshore pipeline (not allowing for transit costs) is around 4,500 km at a cost of around $1.60/Mbtu. The breakeven point has tended to fall over the last decade, as LNG costs have fallen faster than pipeline costs. But technological advances have made possible short-distance offshore pipelines where previously LNG had been the only viable option.

In practice, LNG projects do not often compete directly against pipeline projects for the same supply route. Competition to supply a given market is normally between different supply sources, either by pipeline or LNG. For example, Trinidad LNG competes against Algerian gas supplied through the Maghreb pipeline to Spain.

Pipeline Cost Developments and Prospects

Trends in the cost of pipeline design, construction and operation and particularly the cost implications of new developments in onshore and

Figure 3.11: **Indicative Levelised Pipeline and LNG Costs**



Source: Pipeline costs: Jensen (2000). LNG costs: IEA analysis.

offshore pipeline technology developments will be critical to gas supply prospects in all of the main regional markets. Technology and improved design, engineering and management have reduced pipeline costs. The scope for further unit cost reductions is thought to be large, particularly with the development of high-pressure technology and offshore pipeline design and engineering, including advances in deepwater technology. Higher labour and right-of-way costs may, however, offset to some extent the effect of technological advances in some countries.

High-pressure (HP) technology is expected to play a major role in reducing the unit cost of large-scale, long-distance pipeline projects. Higher pressure permits a larger throughput capacity for a given diameter. Until recently, most large-diameter trunklines of up to 56 inches have been built to operate at no more than around 7.5 MPa. New HP pipelines, now being developed, can operate at pressures of between 10 and 20 MPa.

The main cost benefit of HP over conventional pipelines results from the lower per unit throughput cost of compression, because of the need for fewer stations and higher throughput levels. Marginally higher costs for pipeline material and construction (for higher grade steel, thicker pipeline walls and the handling increased weight) are more than offset by lower unit costs from the increase in capacity. According to several studies, the economic optimum in design pressure is about 14 MPa for a 56-inch-diameter line.[8] HP technology is more economic than conventional technology for an annual throughput capacity of more than 10 bcm, and its competitiveness improves linearly with capacity. Cost savings for a transmission system of 5,000 km with a capacity of 15 to 30 bcm per year, are estimated at 20% to 35%.

Developments over the past decade in *offshore-pipeline technology* have contributed to lower unit costs and have made possible deep-water projects that were previously impossible. Costs have been reduced mainly through improved project design, better construction and inspection activities, lower material costs and increased competition among inspection-service companies.

The most important technological advances in recent years concern deepwater-pipeline projects. Further progress can be expected in the following areas[9]:

- the use of higher grade steels, which reduce pipeline weight (and therefore the amount of steel required) and make pipe-laying quicker and easier;
- improved manufacturing processes, including sophisticated computer techniques for optimising pipe-design criteria that allow for reduced pipe-wall thickness and material-cost savings;
- large-diameter pipeline-laying techniques such as J-laying, which reduces the curvature of the line and, therefore, stress during laying allowing the use of lighter pipes;
- High Frequency Induced (HFI) pipes, an alternative to seamless pipes, which can be up to 30% cheaper due to reduced construction and welding costs;
- advanced seabed-surveying techniques, which permit optimisation of steel weight, concrete coating and trenching for pipeline stability;
- improved insulation to reduce hydrate problems.

Practical examples of the application of these advances include the Bluestream pipeline under the Black Sea, which is under construction and is due to be commissioned in 2001. This project involves the construction of two parallel lines across the sea at a maximum depth of 2,150 metres. Projects at depths of up to 3,000 to 3,500 metres will probably be

8. Scopesi (2000); ENI/IFP (2001).
9. See ENI/IFP (2001) for a detailed discussion of technical developments in offshore (and onshore) pipelines.

technically feasible within a few years. These advances will lower supply costs compared to LNG, where the latter is now the only technical option.

LNG Cost Developments and Prospects

Although the design, engineering, construction and operation of baseload LNG facilities is considered a mature technology, the last five to ten years have seen some major reductions in LNG supply costs. These have come largely from increases in train size, improved fuel efficiency in liquefaction and regasification (mainly from high-efficiency gas turbines in on-site co-generation facilities), improved equipment design, the elimination of gold-plating and better utilisation of available capacity. Liquefaction costs have fallen typically by 25% to 35% and shipping costs by 20% to 30% from 1990 to 2000.[10]

The prospects for further increasing LNG process efficiencies are limited by fundamental thermodynamic principles, but further advances can, nonetheless, be expected in liquefaction and shipping, which could lead to lower overall project costs. Cost reductions in *liquefaction* are currently focused on increasing economies of scale from larger train sizes. Several planned plants, such as Melkoya Island in Norway, Gorgon in Australia and the Gulf of Paria in Venezuela, have train capacities in excess of 4 Mt/year. The additional train planned for the RasGas plant in Qatar will have a capacity of 4.7 Mt/year. Capacities of up to 6 Mt/year, which could reduce unit construction costs by 25% compared to 3 Mt/year trains, should be technically feasible within a few years. Further improvement in fuel efficiency and unit investment costs can be expected from larger gas turbines as train size increases. Optimisation of design parameters, improved reliability, closed-loop cooling systems, the exploitation of cold-recovery and new heat-exchanger designs under development could yield further cost reductions. In the longer term, Floating Liquefaction Storage and Offloading (FLSO) plants could reduce costs even more and make the development of some small and remote gas reserves feasible (Box 3.3). Overall, further cost reductions of the order of 10% to 20% for greenfield liquefaction projects may be possible in the next five to ten years.

10. See, for example Ryan, Bowkley and Baruch (2001). The 3.2 Mt/year Trinidad and Tobago plant, commissioned in 1999, achieved a dramatic reduction in construction costs to an estimated $235/tonne of capacity – the lowest ever.

Box 3.3: **Floating Liquefaction Storage and Offloading plants**

Floating Liquefaction Storage and Offloading (FLSO) plants, where processing and storage facilities are based on a vessel moored offshore in the vicinity of the producing fields, are being developed. This technology can reduce costs by minimising the cost of offshore platforms and pipelines, eliminating the need for port facilities and reducing the time needed to build the plant. Construction can be carried out in a low-cost location and the vessel transported to the production zone. FLSO plants can also address problems that arise when siting facilities onshore. Investors may see them as less politically risky in some countries. A number of technical and safety issues will need to be addressed before FLSO technology can be deployed commercially. It is thought likely at present that FLSO plants will be best adapted to small capacities and medium-sized offshore fields in remote locations. The technology could therefore compete with GTL projects. FLSO plants are under study in Australia (Gorgon and Bayu Undan) and in Angola.

The potential for *shipping* cost reductions is mainly confined to increasing carrier size. The next generation of LNG carriers, now under development, will have a capacity of 165,000 cubic metres, which would yield modest economies of scale. Carriers of up to 200,000 cubic metres, which could potentially reduce unit costs by 10% compared to the current maximum size of 140,000 cm, are being considered. Ultimately, the main limitation on carrier size is the capability of ports to receive larger vessels.

The cost of *regasification* has fallen less than costs for the other parts of the LNG chain since the 1960s. Technology and productivity gains have been largely offset by higher storage costs, the largest single cost component. This has resulted from increased safety standards, more stringent environmental regulations and, in some cases, declining load factors. Rising land costs and increasing public resistance to the siting of receiving terminals are also driving costs higher. Floating terminals have been proposed to lower costs, reduce the time for completing projects and bypass land-use-planning and local environmental constraints.[11] Current technology developments may also make smaller capacities more economic than in the past.

11. For example, floating terminals have been proposed in Italy and offshore United States.

Gas-to-Liquids Technology

Advances in technology, increases in reserves in remote locations and higher oil prices have recently stimulated a surge in interest in developing gas-to-liquids (GTL) projects. GTL plants produce conventional oil products as well as specialist products. All the plants already in operation, under construction or planned are based on the Fischer-Tropsch technology originally developed in Germany in the 1920s. Recent technical advances, including improved catalysts, have significantly improved liquid yields and reduced both capital and operating costs. GTL technology is now seen as a potential alternative to LNG as a way of exploiting gas reserves in remote locations. Pilot projects in recent years have demonstrated the technical feasibility of the technology. Several oil companies are planning to build commercial, large-scale plants. Beyond 2010, GTL plants could potentially lead to the development of a large volume of gas reserves.

Fischer-Tropsch Technology

Fischer-Tropsch GTL technology permits the conversion of natural gas feedstock into synthetic gas (syngas) and its catalytic reforming or synthesis into liquid hydrocarbons.[12] Plant designs vary according to the temperatures at which the synthesis takes place in the reactors and the type of catalyst used. The 30,000 b/d Mossgas plant in South Africa, commissioned in 1990, the first GTL plant built in recent years, uses a high-temperature synthol process, which yields predominantly gasoline. Shell's 12,500 b/d plant at Bintulu in Malaysia, which came onstream in 1993, uses the company's proprietary middle-distillate synthesis (MDS) process. MDS involves the catalytic synthesis of a mixed syngas/hydrogen feedstock, yielding mainly naphtha, kerosene and gas oil as well as some specialist products, such as detergent feedstocks and waxes.

The choice of catalyst is crucial to the performance of GTL plants. Shell claims to have developed new catalysts that improve the gas-to-liquids yield. Whatever the specific technology used, GTL plants are complex and capital-intensive, requiring large sites and construction lead times of two-and-a-half to three years. They are also very energy intensive, consuming up to 45% of the gas feedstock. This characteristic raises concerns about CO_2 emissions. On the other hand, GTL plants generally

12. Syngas, mostly derived from natural gas, is already used extensively to produce ammonia and methanol.

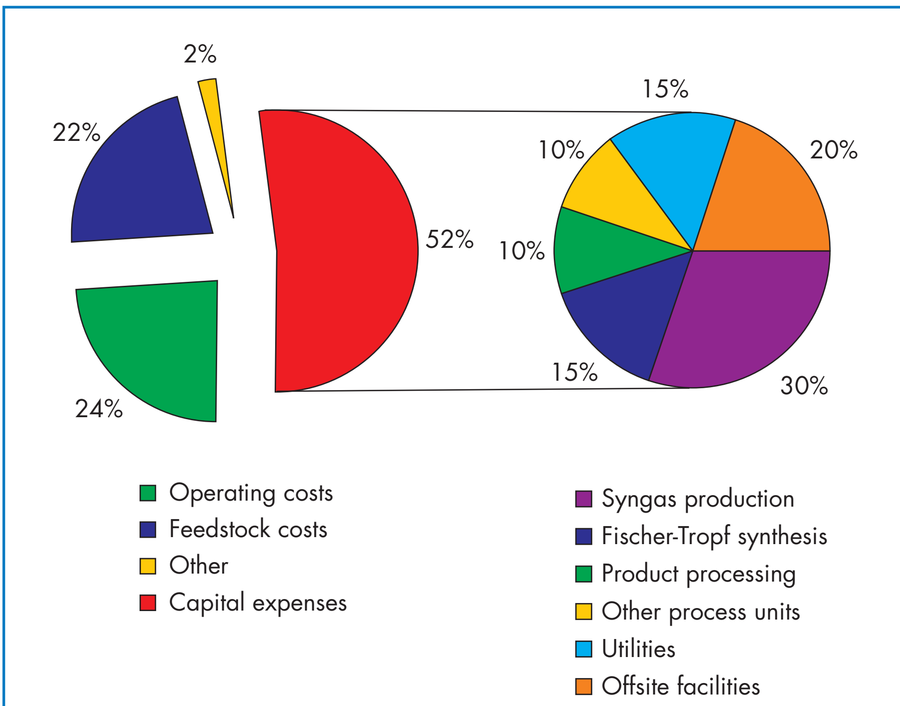
produce a range of middle distillates with good environmental qualities, demand for which is rising.

GTL Economics

The economics of GTL processing are highly dependent on plant construction costs, product types and yields and the energy efficiency of the plant, as well as the market prices of the liquids produced. Capital costs typically account for at least half of total levelised costs for an integrated plant with power production on site. Syngas production accounts for about 30% and the Fischer-Tropsch synthesis process itself about 15% of capital costs, with other processing units, power generation and other services making up the rest.

GTL production costs have fallen sharply in recent years, largely due to improved yields and thermal efficiency. The latest GTL technologies being developed by Shell and Sasol, a South African energy company, are thought to involve capital costs of around $20,000 per b/d of capacity.

Figure 3.12: **GTL Levelised Cost Breakdown**



Note: Based on a 30,000 b/d plant built on a coastal site. Levelised cost is $18/barrel of product output.
Source: Foster Wheeler Energy Ltd, cited in Ghaemmaghami and Clarke (2001).

Table 3.8: **Existing and Planned GTL Plants**

Operator	Location	Output	Capacity (b/d)	Projected Start-up date
In operation				
Mossgas	Mossel Bay, S.Africa	Fuels & specialty products	30,000	1990
Exxon	Louisiana, US	Fuels & specialty products	300	1992
Shell	Bintulu, Malaysia	Fuels & specialty products	12,500	1993
Arco Syntroleum	Washington, US	Syncrude (pilot)	70	1999
Sub-total			42,780	
Under construction or planned				
Rentech	Colorado, US	Fuels & specialty products (pilot)	800	2002
BP	Alaska, US	Fuels (pilot)	300	2002
Conoco	Oklahoma, US	Fuels & specialty products (pilot)	400	2002
Mossgas	Mossel Bay, S.Africa	Fuels & specialty products (pilot)	1,400	2002
Reema	Trinidad	Fuels	10,000	2003
Chevron/Sasol	Escravos, Nigeria	Fuels	33,000	2005
Sasol/QPC	Ras Laffan, Qatar	Fuels	34,000	2005
Syntroleum	W. Australia	Specialty products	10,000	2004
Sub-total			89,900	

Proposed or possible				
PDVSA	Venezuela	Syncrude	15,000	2004
Shell/Pertamina	Indonesia	Syncrude & fuels	75,000	2005
Shell/EGPC	Egypt	Syncrude & fuels	75,000	2005
Shell/NIOC	Iran	Syncrude & fuels	75,000	2005
Shell	Trinidad	Syncrude & fuels	75,000	2005/6
Sicor	Ethiopia	Synfuels	10,000	2003
ANGTL	Alaska	Syncrude & fuels	50,000	2006
Exxon Mobil	Alaska	Syncrude & fuels	100,000	n.a.
Exxon Mobil	Qatar	Syncrude & fuels	100,000	2005
Rentech	Bolivia	Fuels	10,000	n.a.
Forest Oil	S. Africa	N/A	10,000	n.a.
Sub-total			595,000	
Total			726,680	

Source: IEA databases.

A 75,000 b/d plant would, therefore, cost in the region of $1.5 billion. This is nearly twice the cost of a modern oil refinery, which is about $12,000 per b/d of capacity. But GTL can yield a better return on investment than oil refining if natural gas feedstock costs are significantly lower than those for crude oil. Shell claims that its Middle Distillate Synthesis technology is profitable at crude-oil prices of $14/barrel assuming low gas-field development costs[13]. Large-scale commercial development of GTL technology will, however, depend on achieving higher yields of readily marketable products such as gasoline and middle distillates, with lower yields of speciality products, for which markets are limited. The viability of GTL may also be dependent on the absence of any penalty for carbon emissions.

In practice, GTL is likely to compete for investment funds against both oil refining and alternative ways of exploiting gas reserves. GTL may be the preferred option for "stranded" gas reserves, where the cost of piping or shipping the gas as LNG to markets is prohibitive.

Investment Plans and Prospects

With the exception of the 30,000 b/d Mossgas plant in South Africa, which was built in response to oil-trade sanctions during the apartheid era, all GTL plants currently in operation are pilot projects to demonstrate the technical and commercial viability of GTL processes. The Shell Bintulu plant and the Mossgas facility together account for more than 90% of existing capacity. If all the plants under construction or at the detailed planning stage are built, they would triple world capacity. The largest of these plants – including the Chevron-Sasol plants in Nigeria and Qatar, Syntroleum's facility at Sweetwater in Western Australia and Reema's plant in Trinidad and Tobago – are planned to operate on a commercial basis.

A number of other projects have been proposed, including four plants by Shell. Each of these plants – to be built in Egypt, Indonesia, Iran and Trinidad and Tobago – would have a capacity of 75,000 b/d using the MDS process. The Egypt plant would operate alongside a single-train LNG facility. These projects rely on large economies of scale and large reserves. The technologies being developed on a smaller scale could be deployed more widely if they are demonstrated successfully. If all the

13. See Gas Matters (October 2000), *GTL Emerges from the Hague and Bintulu As "A Commercial Alternative to LNG at $15/barrel Oil".*

planned and proposed projects come to fruition, GTL plants would account for about 1% of total oil-product supply worldwide by 2006. It is unlikely, however, that all these projects will proceed.

Prices

Impact of Gas Prices on Investment

The incentive for producers to look for and develop reserves is highly dependent on the price that they expect to obtain for the gas at the wellhead. Together with capital and operating costs and tax and royalty payments, the price determines the future revenue stream and thus the rate of return on the investment. The economics of upstream projects are always based on assumptions about future prices. The evolution of prices can never be known in advance, even where the production is entirely covered by a long-term supply contract. Expectations of future prices, rather than current prices, determine investment in production facilities. Long-term trends in the demand for gas are, of course, also sensitive to gas prices.

How gas prices are determined in practice depends on the physical and structural characteristics of the market and the extent of competition. There is evidence that the introduction of gas-to-gas competition based on third-party access tends to squeeze margins throughout the supply chain. Other things being equal, competition leads to lower prices at the wellhead and at the burner-tip.

Box 3.4: **Gas-Price Formation and the Role of Oil Prices**

The precise manner in which gas prices are determined varies by region and the degree of competition, but gas prices are always strongly influenced by oil prices. In Asia and continental Europe, gas is mostly supplied under long-term contracts, which set a base price and a formula for adjusting that price at regular intervals. The base price has traditionally been negotiated on the basis of the market value of the gas against competing fuels, taking account of the cost of transportation from the delivery point to the point of final consumption.[14] Prices are usually indexed to the price of oil, either crude or one or more oil products (usually heavy fuel oil and distillate) on regional spot markets. Hence, gas prices at the border move in parallel with international oil prices. Sometimes, the gas price may be indexed to the price of another fuel, such as coal or electricity, or to general cost inflation, as well as to oil prices.

Price formation is more complex in markets where gas-to-gas competition based on third-party access to networks has been introduced, such as North America, Great Britain and Australia. In those markets, prices are fixed under very short-term contracts (spot deals) and are determined by the balance of supply and demand at the moment the deal is struck. Prices under medium- and long-term contracts, generally lasting between several months and several years, may be indexed to prevailing spot or futures prices, as is generally the case in North America and increasingly so in Britain, or to the price of oil or another fuel.

Even where gas prices are largely determined by gas-to-gas competition and are contractually decoupled from oil prices, the latter may still play a key role in gas-price formation. This occurs where short-term fuel-switching capability allows end-users to adjust their demand quickly according to relative fuel prices. A sudden rise in the price of heavy fuel oil, for example, may prompt power generators or large industrial consumers to switch temporarily to gas, driving up spot demand and therefore prices. The existence of extensive fuel-switching capacity, both gas-oil and gas-coal, in the United States is a major driver of short-term demand and prices. Prices have tended to fluctuate between coal prices in the South in the summer and heavy fuel oil or distillate prices in the Northeast in the winter.[15] In Britain, gas prices from 1995 to 1998 were largely disconnected from competing fuel prices due to over-supply of gas. But since an interconnector with Belgium was commissioned in late 1998, UK gas prices have been strongly influenced by continental European prices and, thus, indirectly by the price of oil.

14. This netback market value pricing approach is described in detail in IEA (1998).
15. IEA (1998). There is some evidence that fuel-switching capacity in the United States and particularly in California may have declined in recent years, reducing its importance in driving short-term demand and prices.

Gas Price Sensitivity Analysis

The *WEO 2000* Reference Scenario was based on assumed trends in the level of gas prices, differentiated by region. Gas prices were assumed to move generally in line with oil prices, which were assumed to remain flat at \$21/barrel until 2010, then rising to \$28/barrel in real terms between 2010 and 2020. North American gas prices were assumed to begin increasing from 2005 because of dwindling regional reserves. These assumptions rested on the premise that oil prices would continue to play a key role in driving gas price, increasingly through inter-fuel competition at the burner tip as gas-to-gas competition develops.

For the purposes of testing the sensitivity of production to gas prices, we have developed two alternative gas-price scenarios to test the impact of different price levels on regional production levels using the World Energy Model. The results should be treated as indicative given the limitations of the model and data, particularly for countries outside the OECD.

In both the high- and low-gas price scenarios, oil prices were changed proportionately to reflect contractual linkages and inter-fuel competition, so that the oil-price assumptions are consistent with those used for the oil price sensitivity analysis in Section 2. The scenarios take account of the impact of price on demand levels. However, the low price elasticity and cross-elasticities of demand for gas and other fuels mean that the overall level of global gas demand is not greatly different to that in the Reference Scenario.

High Gas-Price Scenario

In the high gas-price scenario, gas prices are assumed to reach the 2020 Reference Scenario levels earlier. The price for North America surpasses slightly that of the Reference Scenario. Higher gas prices could result from higher oil prices or from several other factors, including:

- lower export availability from key producing countries; for example, higher internal demand could reduce the exportable surplus in Russia, South Asia and the Middle East;
- difficulties in building new pipeline capacity;
- a lack of investment in new upstream and transportation capacity;
- geopolitical risks and uncertainties in key producing and transit countries.

Table 3.9: **Gas-Price Assumptions**
($ 2000/Mbtu)

	1997	2010	2020
World Energy Outlook 2000 Reference Scenario			
IEA average crude oil import price (per barrel)	20	21	28
US natural gas wellhead price	2.4	3.0	4.2
European natural gas import price	2.8	2.5	4.2
Japan LNG import price	4.1	3.9	5.5
High Gas-Price Scenario			
IEA average crude oil import price (per barrel)	20	30	30
US natural gas wellhead price	2.4	4.5	4.5
European natural gas import price	2.8	3.4	4.2
Japan LNG import price	4.1	5.5	5.5
Low Gas-Price Scenario			
IEA average crude oil import price (per barrel)	20	15	15
US natural gas wellhead price	2.4	2.1	2.1
European natural gas import price	2.8	2.5	2.5
Japan LNG import price	4.1	3.5	3.5

Source*:* IEA (2000a); IEA analysis.

Low Oil-Price Scenario

In the low-price scenario, gas prices are assumed to remain more or less at the levels prevailing in the late 1990s. This could result from a combination of low oil prices and other factors such as:

- increasing gas-to-gas competition;
- lower supply costs through technological advances;
- more rapid expansion of reserves.

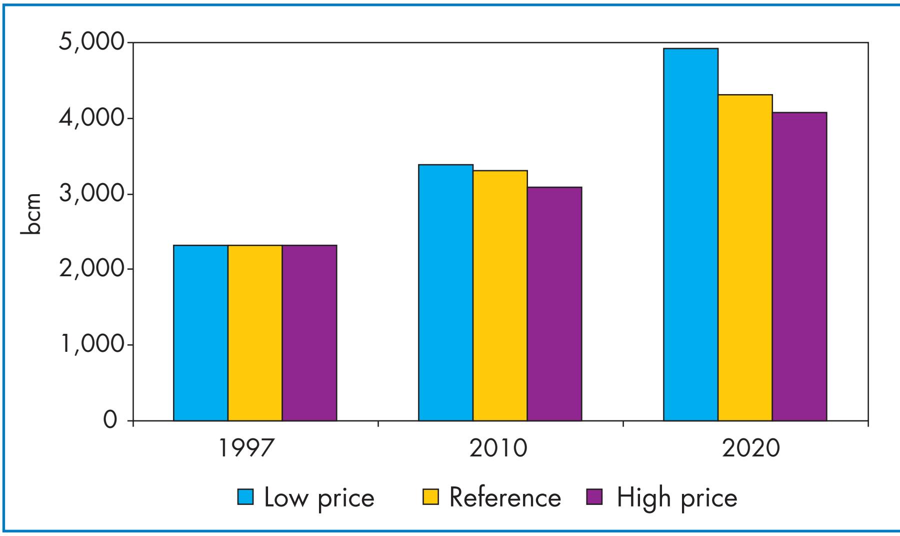
Results

The results of the two cases for cumulative gas production by region are presented in Figure 3.13. The impact on production is greatest before 2010 for the high-price scenario, reflecting the assumption of much higher gas prices in the first half of the projection period. The gap between prices in the low-price and reference scenarios widens sharply after 2010, resulting in a larger impact on production in 2010-2020.

The main conclusions from this analysis are as follows:

- The lower level of OECD import dependency in the high-price case results from a combination of the following factors: a

Figure 3.13: **Global Gas Production Under Different Price Scenarios**



Source: IEA analysis.

reduction in domestic demand growth — demand is 6% lower in the high-price case than in the reference case on average over the projection period; an increase in production as new fields become profitable; investment in exploration and production rises and new technologies are encouraged.

- The developing Asian region, currently a net exporter, will remain self-sufficient to 2010, but will become a net importer by 2020 in all three cases. Due to its large energy needs, low gas prices in this region stimulate demand more than anywhere else. Demand is on average 6% higher in the low-price case than in the Reference Scenario over the projection period.
- The transition economies see their exports fall with a higher gas price. The impact is relatively small, however, mainly because of the low price elasticity of demand and production in the region. Demand is only 3% higher in the low-price case. A higher price reduces demand by 1% on average.
- Latin America, Africa and the Middle East play the role of residual producers. The impact of the price changes on their production and exports is more pronounced. Their production increases on average by 12% over the projection period compared to the Reference Scenario.

Table 3.10: **Net Gas-Import Dependency Under Different Price Scenarios** (%)*

	1997	**2010**			**2020**		
		Low	**Reference**	**High**	**Low**	**Reference**	**High**
OECD	15	31	26	19	40	32	26
Transition economies	-17	-30	-29	-22	-40	-36	-32
Developing Asian countries	-18	0	0	0	23	10	7
Other	-15	-53	-39	-22	-66	-41	-25

*Net imports/demand
Source: IEA (2000a).

Government Policies

Government policies can have a major impact on gas-supply developments, directly and indirectly, through their effect on capital and operating costs, on the final price received or on the ability of companies to site production and transportation facilities. The main areas of government intervention that directly influence the economics of gas-supply projects, not including actions that influence supply through demand, are:

- upstream taxation;
- environmental regulations;
- obligations to maintain a diversity of supply sources for supply-security reasons;
- transit policies;
- liberalisation of gas markets.

Upstream Taxation

The fiscal regime for upstream activities has a major impact on investment returns and, therefore, incentives for companies to explore for and develop gas reserves. Gas production is generally taxed less than oil production because the rent at the wellhead is typically much smaller, as the cost of transporting gas to end users is higher. Nevertheless, the lower netback value of the gas at the wellhead makes gas-supply projects much more sensitive to upstream tax rates. Governments are aware of this. They usually seek a balance between extracting reasonable tax revenues from current production and encouraging new development. Where the economics of gas projects are marginal, governments may refrain from imposing any specific production taxes or royalties. The United Kingdom, for example, levies corporation tax only on profits from fields developed since 1993, at 30%.

Environmental and Land-use Planning Regulations

Environmental and land-use planning policies and regulations can constrain upstream and gas transportation activities and raise costs. Examples of this include:

- limits or taxes on emissions of air pollutants and CO_2 from the fuel used in gas production, processing and pipeline facilities; a growing number of OECD countries, such as Norway, levy carbon taxes;
- restrictions on flaring or venting; many countries strictly control flaring and venting, either to limit greenhouse gas emissions or for economic reasons; where explicit controls do not exist, the government may encourage or oblige oil producers to develop projects to process and distribute by pipeline or in the form of LNG any gas produced in association with crude oil;
- restrictions on siting of production or import-terminal facilities, for environmental or land-use planning reasons; these may greatly complicate and increase the cost of gaining approval for new projects or even prevent development altogether when there is a moratorium, such as on drilling in some parts of the United States; the siting of regasification terminals is becoming very difficult in many countries; in Italy, for example, it has proved impossible in recent years to obtain planning permission to build a regasification terminal at several proposed locations.

It is reasonable to suppose that such policies and regulations will become more onerous with time. This could increase the cost of gas supply, especially from upstream projects where gas reserves are located in pristine environments and unspoilt rural areas in high-income countries. The same is true for regasification terminals in areas of high population density.

Obligations to Maintain Diversity of Supply Sources

Governments of countries that rely on imports of gas for a large proportion of their needs may impose restrictions on the sourcing of gas supply with the aim of ensuring a minimum level of diversity, thereby enhancing supply security. Many European countries have sought to maintain a balance between imports of gas from North Africa, the FSU, other non-European suppliers and indigenous European sources. They have done so by means of procedures for authorising imports and/or direct ownership of national gas companies. Private gas companies have taken similar measures for purely commercial reasons. As a consequence, gas supplies have not always been contracted for on the basis of lowest cost.

The approach to promoting diversity is now changing, with moves to open up downstream gas markets to competition. Some countries, such as Spain[16], France and Italy, have imposed or plan to empower the authorities to impose explicit constraints on large suppliers' portfolios of bulk gas supplies. How the regulatory authorities determine what is an acceptable degree of supply diversity may, in some cases, affect what supplies reach the market. The development of new supply sources and more flexible supply contracts may alleviate these concerns.

Transit Policies

Government policies on transit can have a significant effect on the organisation, costs and risks of cross-border gas-pipeline projects. Governments are responsible for authorising the construction of transit pipelines and levying transit charges to capture part of the economic rent in the gas-supply chain. Competition between potential transit countries will influence the bargaining position of the upstream supplier and can reduce transit fees.

A key issue for the upstream investor is the stability of the investment and regulatory regime in the transit country and the risk of disruptions to the availability of capacity in the transit line or changes in transit fees. This is especially important in the case of long-distance, large-capacity pipelines. Governments can reduce these risks through regional co-operation and cross-border trade initiatives. An example is the Transit Protocol currently being negotiated between Member countries of the Energy Charter Treaty. This Protocol is intended to provide a common legal and regulatory foundation for the construction and operation of a network of multiple energy-transit routes across regions. The Protocol could play a major role in promoting long-distance gas-pipeline projects, especially in the transition economies.

16. The 1998 Hydrocarbons Law states that no one country can supply more than 60% of gas consumed in Spain.

Box 3.5: **Transit Protocol**

The objectives of the Protocol are to oblige governments to:

- ensure that energy flows passing through their territory in transit are not interrupted;
- make transparent the criteria used for setting transit tariffs;
- facilitate the construction, modification and operation of transit infrastructure;
- ensure that access to and use of available transit capacity is granted on a transparent and non-discriminatory basis; this provision will not, however, entail an obligation to provide mandatory third-party access to pipeline systems.

Liberalisation of Gas Markets

Governments around the world are liberalising their gas industries by introducing gas-to-gas competition, usually based on mandatory third-party access to gas supply infrastructure. In some cases, it involves privatising public utilities. The speed and character of reform differ markedly among countries. Although regulatory and structural reforms in most countries are far from complete, experience in North America and Britain suggests that gas-to-gas competition can reduce supply costs and end-user prices in mature industries.

Box 3.6: **Regulatory and Structural Reform in the Global Gas Industry**

The United States and Canada were the first countries to introduce third-party access, initially on a voluntary basis, in the mid-1980s. Competition in the wholesale inter-state industry is now well established. Similar reforms were launched in the late 1980s in Great Britain, following the privatisation of the monopoly gas company, British Gas. The UK Government has gone further than the governments of Canada and the United States by extending mandatory third-party access to the entire network and to all consumers in 1998. Reforms are still being implemented in Europe, where the 1998 EU gas directive came into effect in 2000, and in Australia. Several EU countries have expressed their intention to open their markets fully over the next decade. Competition is starting to emerge in Europe and Australia. Argentina was the first country outside North America and Britain to introduce third-party access, in 1992, but effective competition has been slow to develop there.

Market Developments

Impact of Competition on Supply

Gas-to-gas competition based on third-party access involves fundamental changes in the contractual relationships between different market players and the emergence of new entrants. In North America and Britain, where competition has developed most, these changes include:

- diversification of the services available to wholesale and retail buyers, including bundled and unbundled transportation and supply, and tailored transportation and storage services;
- a huge increase in the number and complexity of transactions, requiring major investment in sophisticated information and communication systems;
- the emergence of financial risk-management instruments including futures and options contracts;
- a shift to shorter-term contracts for transportation and related services, and for the supply of gas itself; spot markets — informal markets for over-the-counter trades of fixed volumes of gas at a negotiated market price — are now a central feature of the North American and British gas industries; they are increasing in importance in other countries, including Australia, Argentina and some European countries; it is unclear how a possible increase in reliance on imports or more distant indigenous sources will affect gas and capacity trading in the United States and Britain;
- a move away from indexation of gas prices to the prices of competing fuels towards the use of spot or futures gas-price indexation in medium- and long-term gas supply contracts;
- an increase in the volatility of short- and medium-term gas prices.

Competition also affects gas prices at the wellhead and at the burner-tip. In practice, estimating or forecasting the impact of third-party access on prices and margins in the different parts of the gas supply chain is very difficult. It requires detailed information about costs and the establishment of a baseline for market evolution. Nonetheless, experience in North America and Britain suggests that competition tends to squeeze margins, reduce the size of rent in the value chain and result in lower wellhead and final prices. In both cases, wellhead prices fell following the introduction of third-party access, largely in response to over-supply, although prices rebounded in 1999 and 2000 with higher oil prices and tighter gas supply.

The pace of development of effective competition is, therefore, a key factor affecting upstream developments. To the extent that it results in lower wellhead/border prices, increased competition could undermine the economics of upstream developments. But competitive markets provide much greater opportunities for producers to market their gas. By reducing downstream transportation costs, competition may also allow for higher netbacks at the wellhead. This may offset some of the effect of lower end-user prices.

In North America and Great Britain, competition does not appear to have undermined the development of gas reserves and supply infrastructure. But that may owe much to the specific structural characteristics of those markets when competition emerged. In North America, investment in upstream projects and transmission capacity has increased since restructuring in the 1980s and early 1990s in response to strong demand growth, despite historically low wellhead prices up to 1999.[17] In Britain, upstream investment – mostly in offshore developments – increased in the 1990s compared to the previous decade, although the sharp fall in prices in 1994/5 resulting from over-supply led to a delay in some new field developments. Development projects are still generally based on medium- or long-term contracts with power projects or marketers, but the length of these contracts has declined in recent years and no longer necessarily cover the entire output of the field. In both North America and Britain, risk-management instruments have been developed to help producers cope with increased price volatility.

Despite these trends, major gas companies in Europe are worried about the impact of competition on the development of large-scale upstream supply projects. The *WEO 2000* Reference Scenario projects that almost all growth in gas demand in the coming decades will be met by increased imports from Russia, Algeria, Norway, the Middle East and West Africa. Projects to develop reserves and transport them to Europe are "lumpy", requiring massive investment in production facilities as well as long-distance pipelines or LNG facilities – often costing more than $1 billion. The Yamal Russia-Europe project, for example, is expected to

17. EIA (1999).

cost in total up to $50 billion, although it is being pursued in phases to minimise risk. Over the past four decades, such large-scale investments have been made possible by stable relationships between national monopoly producers and marketing organisations and monopoly downstream gas companies based on long-term take-or-pay contracts.

European gas companies have argued that experience from North America and Britain, which supports the view that large investments are possible under competition, is not relevant to Europe for three main reasons:

- Most investment in North America and Britain is incremental, and thus carries less market risk than grass-roots projects.
- Major new grass-roots projects, such as the development of offshore gas fields, usually involve investment of only tens or at most hundreds of millions of dollars rather than the billions needed for major long-distance pipeline or LNG projects to bring gas to Europe.
- The risks of dealing with producers in North Africa, the Middle East and the FSU are much greater than those associated with Canada or the North Sea.

Despite these arguments, long-term take-or-pay contracts may prove to be less necessary than before in securing financing for big projects in Europe and elsewhere, since spot markets can now take any volumes that a gas company contracts for but is unable to sell directly. The ultimate guarantee of volume, therefore, is arguably the growth of demand in the European market as a whole.

Increasing competition in power generation, however, will lead to greater uncertainty over future demand, since gas-fired generators will not be able to guarantee to always take the gas. In addition, competition does not necessarily increase the price risk to producers, since existing netback-pricing arrangements with periodic price re-opener clauses already put much of the price risk on the producers. Nonetheless, it is likely that regulatory and market uncertainties, wherever they occur, together with the additional price volatility that is likely to result from gas-to-gas competition will lead to a perception of greater overall project risk. This could raise the cost of capital, skew investment towards smaller, closer-to-market projects and delay investment in multi-billion dollar projects.[18] For

18. The leading European gas companies have often voiced these concerns. See, for example, Bergmann (2000) and Haerberlin (1997).

the latter to proceed, long-term take-or-pay contracts will probably still be necessary. Close collaboration between upstream and downstream companies and enhanced dialogue between the governments concerned would reduce investment risk.

Regional and Global Market Integration

Rising demand and expanding transportation networks are leading to a much greater degree of market integration at the regional level, although a truly global gas market does not yet exist. The construction of inter-state and cross-border interconnectors has integrated networks in the United States and Canada and in Europe, with interconnectors between the continent, the United Kingdom and Ireland and with external pipelines from the FSU and Algeria. Regional networks are also emerging in the Latin American Southern Cone and in Southeast Asia. Regional market integration is expected to grow as new pipeline projects are commissioned.

There are few physical connections between the main established regional markets. But these could significantly increase with rapid expansion in LNG trade. This development, which would replicate the evolution of the international oil market, would have major implications for gas supply. Prices in connected regional markets could be expected to converge depending on the ability of suppliers to switch volumes between supply routes and markets.

Traditionally, LNG projects have been based on fixed supply chains, underpinned by long-term take-or-pay contracts. Now, however, there are signs that the LNG market is becoming more flexible, as international trade and its global coverage grows and as downstream markets gradually open up to competition. As more projects come on stream, the scope for buyers to securing additional supplies is increasing. At the same time, buyers are increasingly looking for short-term supply flexibility. In recent years, increasing volumes of LNG have been traded on the spot market and trade flows have changed in response to regional market factors. Short-term sales amounted to around 4% of total LNG trade in 1999, compared to only 2.4% in the previous five years.[19] Spot trading continued to grow in 2000, with a surge in deliveries of Algerian and Trinidad LNG to the US East Coast in response to very high North American gas prices.

19. Petroleum Economist (January 2001).

A number of global LNG traders are emerging. Enron, a big American energy trading firm, is planning to launch on-line LNG trading by 2002 and is chartering carriers to be operated without any long-term contractual ties to any particular supply source. Other firms, including BP and Shell, have placed orders for carriers without any firm commitment to specific projects. The key to market growth in the near term is likely to be demand for LNG in the North American market, which will probably hinge on prices of at least $3/Mbtu. European buyers could play an increasingly important role in boosting spot volumes in the coming years depending on prices and access to import terminals.

The continued growth in short-term LNG trading could spur a fundamental change in the way new LNG projects are structured. Some observers believe that financing of gas-field development and liquefaction projects can be done without tying all the capacity to long-term contracts. This will happen if investors are confident that a fungible international market ensures full use of capacity. The Oman project, for example, has proceeded on the basis of a long-term contract with Kogas in Korea to supply only 4.1 million tonnes per year out of a total capacity of 6.6 Mt. Similarly, small regasification terminals could be built and operated on a merchanting basis. Alternatively, global gas traders may be prepared to take on a certain amount of risk by signing long-term supply contracts with LNG producers with prices tied to spot gas prices or oil prices but without back-to-back long-term sales contracts with buyers in place. These changes could in turn lead to greater commercial opportunities for LNG projects to proceed, thereby enhancing the prospects for international trade.

Regional Analysis

North America

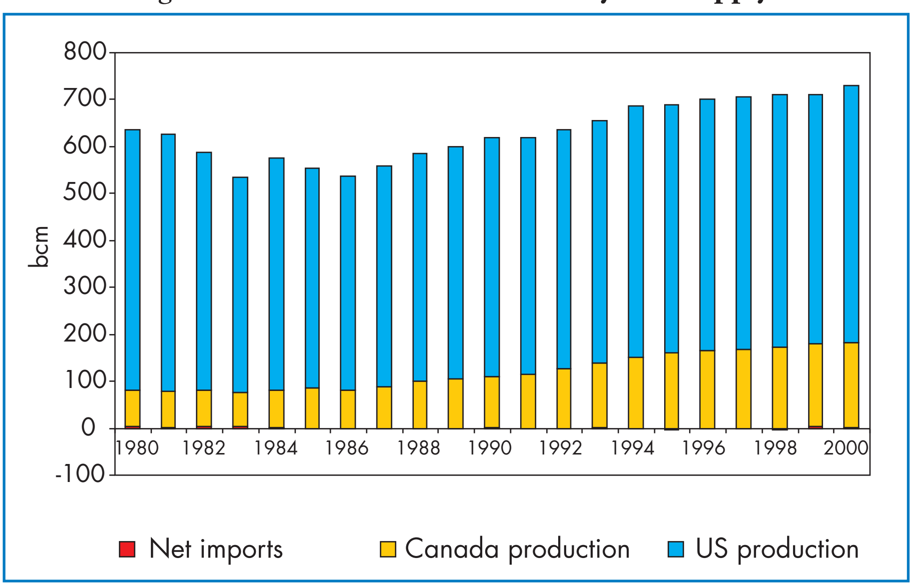
Market Overview

The major pipeline links and the substantial flows of gas from Canada to the United States mean that the two countries' systems may be considered a single network, although interconnection between them varies considerably among states and provinces. The western United States is more closely integrated with Canada than it is with the eastern US market. Mexico is also connected to the US market, but the capacity for exchanges is small. For the purposes of this analysis, North America is assumed to cover Canada and the United States only.

The combined North American market amounted to 733 bcm of primary gas supply in 2000 – equivalent to 29% of global gas supply. Of this, the United States accounted for 643 bcm. The region is largely self-sufficient in gas, although imports in the form of LNG picked up in 2001 due to high prices. In 1999, the region was a small net importer of gas, with imports of LNG mostly from Algeria and Trinidad and Tobago into the US East Coast just offsetting small net volumes of US gas exports to Mexico by pipeline and to Japan from Alaska in the form of LNG. North American gas consumption has been rising steadily since the mid-1980s. Most of the increase has been met by Canadian production. Gas consumption is projected to rise at an average annual rate of 1.3% from 1997 to 2020.

Production is concentrated in the southern and central US states and in Western Canada. Texas and Louisiana together account for close to half of total North American dry gas production. The main basins are in the Gulf of Mexico (onshore and offshore), the lower Midwest, the Permian Basin on the Texas/New Mexico border, the San Juan Basin in the Southwest, the Rocky Mountains and the Western Canadian Sedimentary Basin (WCSB) centred on Alberta. Most gas is produced from gas-only wells.

Figure 3.14: **North American Primary Gas Supply**



Note: 2000 data are preliminary; production is gross.
Source: IEA (2001a).

The region has a vast network of high-pressure interstate and inter-province pipelines that carry gas from the major producing areas to the main markets both within the producing regions and in the Northeast, Midwest and California. The Northeast is the largest consuming region, served by some 25 major pipelines from the Southwest, Midwest and Canada.

The North American gas industry has undergone profound structural changes over the last two decades, largely due to regulatory reforms aimed at promoting competition and improving efficiency. This process began with the lifting of controls on wellhead prices, followed by mandatory open access to the interstate pipeline and storage system and the unbundling of pipeline companies' gas trading, transportation and sales activities. Several states and provinces are now expanding open access and retail competition to small residential and commercial consumers. To date it is mostly limited to industrial and large commercial end-users. Pricing of transmission and distribution services remain for the most part regulated by the national regulators, NEB in Canada and FERC in the United States, and by state and provincial regulators on a traditional cost-of-service basis.

Reserves and Resources

There is an estimated 6.55 tcm of proven natural gas reserves in North America, 4% of global gas reserves. Just under three-quarters of the reserves are in the United States (Table 3.11).

Table 3.11: **North American Proven Gas Reserves and Undiscovered Resources** (bcm)

	Proven reserves (at 1 January 2001)	**Undiscovered gas resources (mean, on 1 January 1996)**
United States	4,845	14,914
Canada	1,705	694*
Total	6,550	15,608

* According to the NEB, estimates of undiscovered conventional resources amount to 3.37-5.38 tcm.
Sources: Reserves – Cedigaz (2001); Resources - USGS (2000).

Canada

The National Energy Board estimates remaining established Canadian reserves of marketable gas at the beginning of 1999 at 1.65 tcm, 75% in Alberta and 14% in British Columbia. Cedigaz's estimates at 1 January 2001 amount to 1.7 tcm. Exploration has surged in the past two years, with more than 8,000 new gas wells drilled in 2000 compared to 6,330 in 1999. However, additions to reserves have not fully offset gas production. Since 1994, proven gas reserves have declined by 200 bcm. Almost all of Canadian gas production comes from the Western Canada Sedimentary Basin (WCSB) in British Columbia, Alberta and Saskatchewan, where most gas reserves are located. The reserves-to-production ration in the WCSB declined to 9.6 years in 1999. There are also significant gas accumulations in the Mackenzie Delta, the Beaufort Sea, the Northwest Territories, and offshore Atlantic (Scotian Shelf). NEB estimates Western Canadian coalbed methane (CBM) resources at 2.12 tcm.

United States

Proven natural gas reserves were 4.74 tcm at the beginning of 2000 according to the Department of Energy's Energy Information Administration and 4.85 tcm at the beginning of 2001 according to Cedigaz. Seven states or areas account for 75% of the US proved gas reserves: Texas (25%), Gulf of Mexico Federal Offshore (15%), New Mexico (9%), Wyoming (8%), Oklahoma (7%), Alaska (6%) and Louisiana (6%). Reserve additions replaced 118% of gas production in 1999. About 30% of all discoveries were in the Gulf of Mexico Federal Offshore and 28% in Texas.

The US gas-resource base is very large. The USGS puts undiscovered resources at 14.9 tcm with a range of 11.1 to 19.7 tcm. Estimates by the American Gas Association are even larger: 35.6 tcm at the end of 2000 – equivalent to 63 years of current production. The Association stressed the need, however, to open more federal lands to drilling in order to tap this full potential. In the past fifteen years, there has been little incentive for intensive exploration because of surpluses in the system in both the US and Canada. Both regions are now approaching deliverability limits that require accelerated reserve additions if producing capacities are to grow.

Unconventional gas resources are also large. The USGS estimates technically recoverable resources of coalbed methane for the lower 48 States at 1.2 to 1.6 tcm, with a mean estimate of 1.4 tcm. The US Department of Energy puts proven reserves at 375 bcm.[20] US production

20. EIA (2000).

of unconventional gas (tight ands, gas shales and CBM) in the United States has grown from 2 tcf (57 bcm) in 1990 to 4.7 tcf (133 bcm) in 2000 – equivalent to 25% of total US gas production.

Production Prospects

The prospects for North American gas production depend on the ability of, and incentives for, producers to discover and develop conventional and unconventional reserves and to connect them to markets. Higher output will require increased drilling in established producing basins in the lower-48 US states and Canada, as well as new greenfield projects.

Established Producing Basins

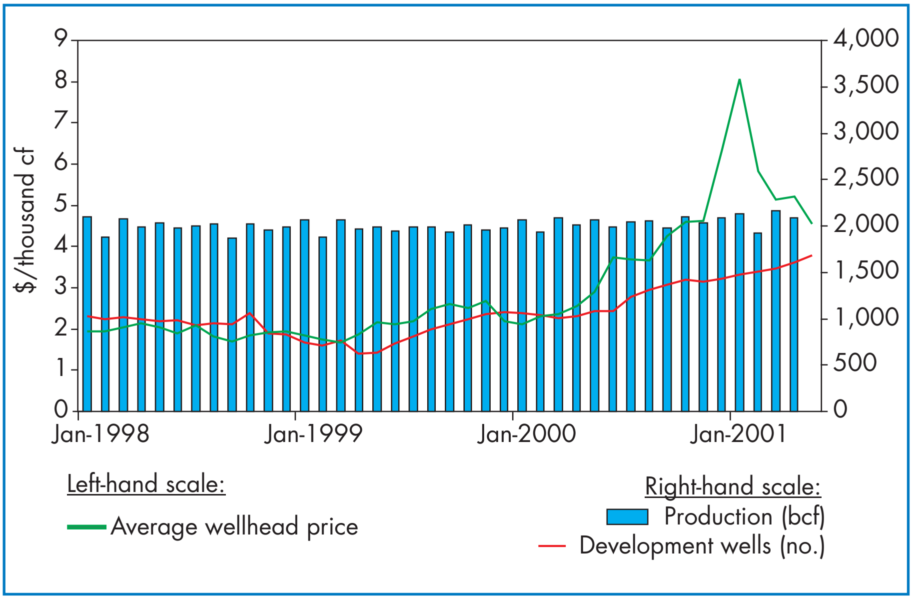
Among current producing basins, attention is expected to shift to deeper water in the Gulf of Mexico and to unconventional reserves, particularly tight-formation and shale-gas deposits, and CBM, the production of which is currently centred on the Rocky Mountains. Production from these sources is expected at least partly to offset declines in conventional output from other onshore areas and shallow-water offshore fields in the Gulf of Mexico. There are signs that output from these areas may decline more rapidly than previously thought.

Wellhead prices, which have a direct affect on drilling rates, are a key determinant of trends in installed production capacity. New production capacity for conventional wells can usually be brought on stream within six to eighteen months of the start of drilling. Figure 3.15 illustrates the sensitivity of development-well drilling – a key measure of drilling activity – to wellhead prices in the United States. The number of development wells completed dropped when prices stagnated in 1998, and recovered steadily with the rebound in prices in 1999 and 2000. The number of exploratory wells and the number of gas rotary rigs in operation have also followed recent short-term movements in wellhead prices.[21] In recent months, drilling has been limited by lack of rig availability.

Despite the recent surge in drilling, US natural gas production has not increased as fast as past trends would have suggested. This is illustrated clearly in Figure 3.16. Drilling activity increased 45% in 2000, while production rose by only 4%. About half of all gas-drilling rigs in the world are now deployed in the United States, despite minimal increments to

21. The US natural gas rig count grew from a weekly average of 496 in 1999 to 720 in 2000 and 898 in February 2001.

Figure 3.15: **Wellhead Gas Prices, Development Gas-Well Completions and Gross Gas Production in the United States**
(Monthly, January 1998-May 2001)



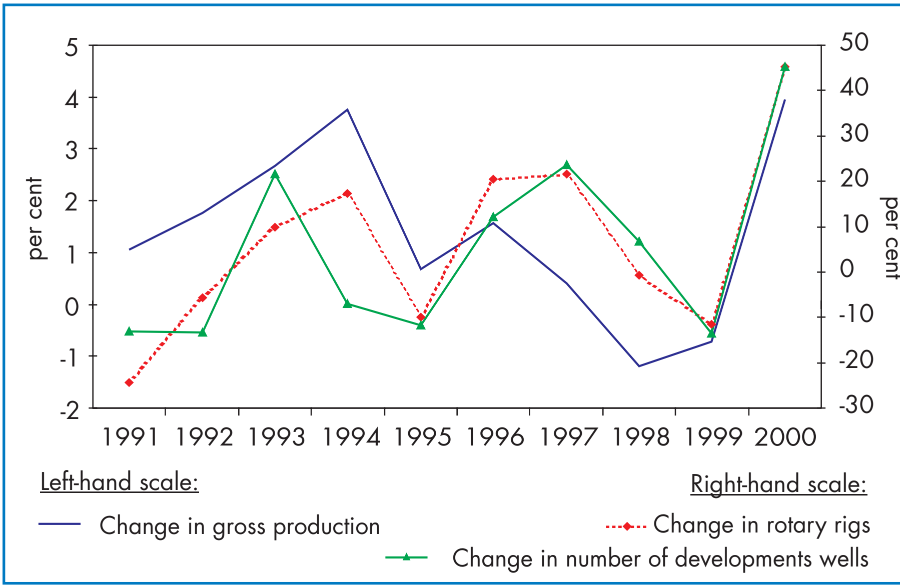
Source: EIA, *Natural Gas Monthly* (various issues).

production. There appear to be three main reasons for the diminishing responsiveness of production to drilling: increasing decline rates, falling drilling-rig efficiency and a shift in drilling from conventional wells to deepwater sites and CBM.[22] Salomon Smith Barney[23] estimates that gas-field decline rates have increased steadily in recent years, from 15% in the early 1990s to around 27% in 2000. This is partly explained by the growing weight of the Gulf of Mexico, where decline rates tend to be much higher, in total US production.[24] Decline rates tend to increase with the life of a gasfield, especially in the case of small deposits. Much of US gas production comes from fields that have been in production for several decades and are reaching the end of their productive lives, and from small

22. The decline rate is defined at the rate of decline in gas production net of production from new wells (i.e in the absence of new drilling). Thus, a 20% annual average decline rate and stable overall production implies that 20% of total production in the year in question is from new wells. Rig efficiency is a measure of the amount of new production capacity that is added by drilling rigs in operation over a given period.
23. Salomon Smith Barney (2001).
24. Production from new wells in the Gulf of Mexico in their first year are currently declining at a rate of almost 50%; see World Gas Intelligence, *Shallow Gulf Wells Swing US Supply* (22 August 2001).

fields. In addition, average rig efficiency fell from around 26 Mcf/day of capacity added in the January of the following year per rig in 1993-1995 to 19 Mcf/d/rig in 1998, 22 Mcf/d/rig in 1999 and as low as 10 Mcf/d/rig in 2000 according to preliminary data. The growing emphasis on deepwater and CBM projects, which have much longer lead times, may also be dampening the sensitivity of production to drilling activity.

Figure 3.16: **Annual Change in Gross Gas Production, Average Number of Rotary Rigs in Operation and Development Well Completions**



Source: EIA, *Natural Gas Monthly* (various issues).

If these trends in decline rates and average rig efficiency persist, development-drilling rates will have to increase just to maintain current production levels. This will require heavy investment in new onshore and offshore rigs. Increasing decline rates also imply rising field-development costs. Technological advances, however, could make new rigs more productive, offsetting to some extent the impact of rising decline rates and tempering the need for new rig construction. On balance, however, it seems likely that gas-production costs from mature onshore and offshore basins will go on rising. That points to a need for higher wellhead prices than in recent years to provide sufficient incentives for producers to drill more wells. That said, the prices of late 2000 and early 2001 are undoubtedly unsustainable in the medium term.

Official analyses of resource availability and development costs support this conclusion. The EIA currently projects an increase in wellhead gas prices in real terms, from \$2.08 per thousand cubic feet (roughly equivalent to 1 Mbtu) in 1999 to \$2.69 in 2010 and \$3.13 in 2020 due to rising marginal supply costs.[25] These projections are sensitive to assumptions about the pace of technological progress in the upstream industry. In a rapid-technology case, prices remain flat at around \$2.50 until 2020. In a slow-technology case, prices rise steadily from \$2.50 in the first decade of the millennium to over \$4 by 2020. The study does not detail average production costs.

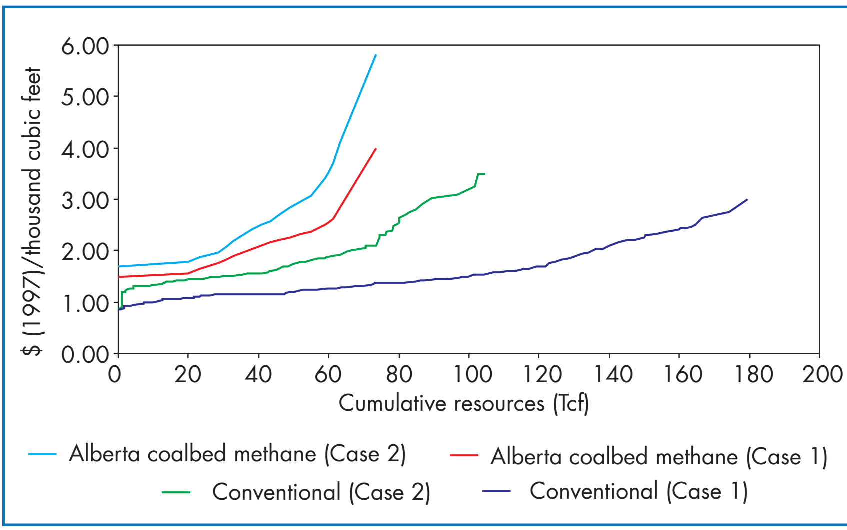
National Resources Canada (NRCan) also projects rising wellhead prices in North America due to increasing marginal production costs, but at a slower rate than in the EIA's projections. NRCan foresees that prices will average around \$1.50/Mbtu from 2000 to 2005, rising slowly to \$1.90/Mbtu in 2010.[26] NRCan acknowledges that industry projections show higher prices, ranging from just over \$2/Mbtu to \$3/Mbtu in 2010. A 1999 study by the National Energy Board provides estimates of the cost of supplying gas from undiscovered conventional and unconventional resources from the WCSB. Assuming a 5% annual reduction in costs and a similar improvement in finding rates (Case 1), the NEB estimated that more than 100 tcf (2.8 tcm) of gas could be produced from undiscovered conventional resources at less than \$1.50/Mbtu and a further 80 tcf (2.3 tcm) at less than \$3.50/Mbtu. Current finding and development costs are thought to average well under \$1/Mbtu.[27] Cumulative WCSB production to the end of 1997, the cut-off date for the NEB analysis, was 102 tcf (19.2 tcm). An estimated 50 tcf (1.4 tcm) of CBM could be developed at a cost of under \$2.25/Mbtu.

A key uncertainty for US gas-production prospects concerns access to resources on federal lands. At present, two of the most promising regions for future production – the Rocky Mountains and the Gulf of Mexico – are subject to strict access restrictions due to environmental concerns or multiple-use conflicts. For example, the National Petroleum Council (NPC) estimates that 40% of the estimated 3.9 tcm of resources in the

25. EIA (2001).
26. Natural Resources Canada (2000).
27. A Canadian Energy Research Institute study by Quinn and Luthin (1997) estimated finding and development costs for natural gas in Western Canada in 1996 at 66 cents/thousand cubic feet in money of the day.

Rocky Mountains is located on Federal lands that are either closed to exploration or subject to restrictive provisions.[28] The eastern Gulf of Mexico, where an estimated 0.7 tcm of resources are located, is largely closed to exploration. The US East Coast is entirely off-limits, while drilling on the West Coast shelf also faces severe restrictions. Loosening of these restrictions, which will only happen if producers demonstrate that they can reduce the "footprint" of exploration, production and transportation activities, could boost US production and lower costs. The NPC projects that lifting current restrictions could lead to a 45 bcm increase in production and a 45 cents/Mbtu cut in marginal supply costs in 2015. The new Administration has shown increased willingness to ease access restrictions.

Figure 3.17: **Western Canada Sedimentary Basin Supply Costs**
(US $ 1997 per thousand cubic feet)



Note: Costs include exploration and development expenses, operating costs, taxes, royalties and a 6% real rate of return on investment. It is assumed that technology reduces costs and increases finding rates by 5% per annum in Case 1 and 2% per annum in Case 2.
Source: National Energy Board (1999).

New Indigenous Supply Sources

New indigenous North American gas supply options include developing reserves in new North American basins, exploiting new unconventional gas resources and marketing Alaska gas:

28. National Petroleum Council (1999).

- *New conventional gas basins:* The most promising undeveloped reserves are in offshore Atlantic basins in Labrador, Newfoundland and Nova Scotia (where small-scale production started in 2000) and the Mackenzie River Delta/Beaufort Sea region in Northern Canada. Beyond 2010, attention may shift to frontier regions such as the Arctic Islands and the Northwest Territories, depending on developments in drilling technology in extreme weather conditions. Interest in East and West Coast US resources will depend on the loosening of current access restrictions.
- *Unconventional resources:* Large volumes of unconventional gas resources in the United States and Canada could be tapped from new basins, although generally at higher cost than conventional resources. US tight sands and Alberta CBM could play a major role in North American supply after 2010. Table 3.12 summarises the results of a recent study of the potential for US unconventional gas production under different assumptions about technological progress. In the most optimistic case, unconventional gas output is projected to increase to over 225 bcm per year.

Table 3.12: **US Unconventional Gas-Production Outlook** (bcm)

	1999 production	**2020 reference case**	**2020 low technology case**
Tight sands	82	161	99
CBM	37	48	25
Gas shales	11	31	14
Total	130	240	138

Source*:* Kruuskraa and Kuck (2001).

- *Alaskan gas*: LNG and pipeline projects based on the large gas reserves on the Alaskan North Slope, largely unexploited so far, are now under consideration. Additional LNG would most likely be shipped to California, if permission to build a regasification terminal is obtained, or exported to Mexico or Pacific Rim markets. GTL is another possibility. A small test facility is already under construction and will be commissioned by 2003. Another possibility, which is currently gaining increasing support, is a 35 bcm/year high-pressure pipeline to link North Slope reserves to the US lower-48 via Western Canada. One option is to route the line offshore through the Mackenzie Delta and down to the Alberta hub at Windfall. Another is to route the line south through Fairbanks, to supply the local market, then on to Windfall through the Yukon. Either project would face major environmental and technical obstacles, and delays in obtaining regulatory approval. BP, the main sponsor of the project, believes that the cost of transporting the gas to US markets could be less than \$2/Mbtu.[29] The earliest date suggested for commissioning is 2007.

Prospects for Imports

Imports of gas by pipeline from Mexico or as LNG from Atlantic Basin suppliers are another supply option for North America. High production costs for existing producing basins and for new indigenous sources are likely to drive wellhead prices higher over the next decade or so. This will increase the attractiveness of imports. LNG, in particular, looks set to fill much of the growing gap between indigenous output and demand.

LNG

LNG is expected to play a growing role in North American gas supply in the long term. At present, only two of the four LNG import terminals in the United States – at Lake Charles, LA and at Boston, MA – are currently operational. The two mothballed plants – at Elba Island, GA and Cove Point, MD – are expected to be reopened by late 2001 and in April 2002, boosting total import capacity from 24 to 32 bcm/year. Capacity expansions at these facilities and potential investment in new LNG terminals in the US lower-48 will depend on prices and project-development costs. Brightening the prospects for LNG are expected increases in the cost of gas from domestic sources, continuing falls in the costs of LNG processing and transportation and the possible development of an Atlantic Basin LNG spot market. Each of these trends could help create commercial opportunities for LNG imports into the US East Coast and possibly the West Coast (directly or via Mexico).[30] There have recently been proposals for regasification terminals to be sited in California, Baja

29. Gas Matters, *Why Alaska-Lower 48 Pipeline is Suddenly a 'This-Decade Project'* (December 2000).
30. Texaco recently announced that it is considering a plan to build an offshore regasification terminal in the Gulf of Mexico, with the LNG most likely coming from Angola. A project to supply the US West Coast with Bolivian LNG (with a plant to be sited in Chile or Peru) is also under consideration.

Figure 3.18: **Potential New Gas-Supply Options in North America**

California (in Mexico), Florida and the Gulf of Mexico, although siting may be difficult due to environmental concerns.

Mexico

Although Mexico has a large natural gas-resource base, gas trade in recent years has mainly consisted of small volumes of net imports from the United States. To reverse the trade pattern would require major investment in the Mexican upstream sector and transportation infrastructure. Supply would also have to outpace the increase in domestic consumption. The potential for large-scale exports of Mexican gas to the United States will probably be greater after 2020. In the meantime, the emphasis will be on meeting domestic requirements first.

Pipeline-Network Expansion

There will be a need for substantial investment in new transmission and distribution capacity in North America, including new lines to bring gas from Canada into the United States. How much new capacity will be needed will depend on the load factor[31] of incremental demand (the higher the load factor, the less capacity is required) and the location of new supplies. Since much of the increase in demand will probably come from the power sector, the needed increase in transmission capacity is likely to be proportionately less than the overall growth in the market, because the load factor of power-sector demand will probably be higher than average.

The EIA forecasts that inter-regional US transmission capacity, including imports, will grow at an average annual rate of about 0.7% between 2001 and 2020, down from 3.8% between 1990 and 2000.[32] Most expansion projects over the next two decades are expected to involve looping and added compression. As a result, incremental capacity costs will probably be lower than in the past. The total cost of new capacity is estimated at around $45 billion, assuming a 50% increase in demand over the period 1999 to 2020. Increasing reliance on gas located far from major markets – such as the WCSB, Alaska, Northern Canada and Nova Scotia/Newfoundland – could increase the need for new capacity and the size of required investment in the longer term.

31. Average daily system throughput (or consumption) divided by peak daily throughput.
32. EIA (1999).

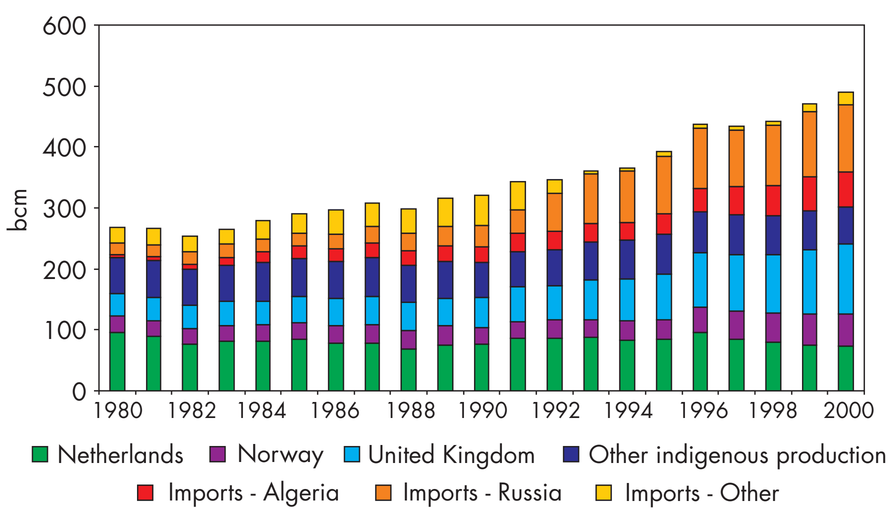
OECD Europe

Market Overview

With total gas consumption of 471 bcm in 2000, OECD Europe is the third largest regional gas market after North America and the FSU. Natural gas demand grew at an average rate of 3.7% per annum from 1973 to 2000. The residential/commercial sector is the single largest consuming sector, followed by industry, but the use of gas in power generation is growing rapidly.

Indigenous production, concentrated in the United Kingdom, Norway and the Netherlands, has grown in recent years, but not fast enough to keep pace with demand. Imports have therefore increased, accounting for 36% of total European gas needs in 1999 compared to only 16% in 1980. Russia is the most important external supplier to Europe, providing just under two-thirds of total net imports and a quarter of total supply – entirely by pipeline. Algeria is the next biggest exporter of gas to Europe, both via pipeline and as LNG. Imports of LNG from Nigeria began in 1999 and from Trinidad and Tobago in 2000. Europe has also been importing small volumes of LNG from Libya since the early 1970s and occasional spot cargoes from the Middle East and Australia in recent years.

Figure 3.19: **Gas Production and Supply in OECD Europe**



Note: 2000 data is preliminary.
Source: IEA (2001a).

Within Europe, Norway exports significant volumes of gas to the Continent and smaller volumes to the United Kingdom. The Netherlands also exports gas to other European countries. The United Kingdom has generally been an exporter of gas to the Continent in recent years, but sometimes has to import gas during periods of peak demand. The British and Continental markets have been physically linked by a 20 bcm/year interconnector since 1998.

The continental European gas market is dominated by a small number of vertically-integrated national gas companies. Efforts at the national and European level to liberalise gas markets are bringing a degree of competition in gas supply and fostering short-term (spot) markets. The pace of market reform varies widely across the region. Gas-to-gas competition is most developed in Britain, where structural and regulatory reforms were first launched in the late 1980s and 1990s.

Resources and Production Prospects

At 7.3 tcm, OECD Europe proven gas reserves represent 4.5% of the world total. About 80% of the region's reserves are in Norway, the Netherlands and the United Kingdom. Europe possesses two of the planet's twenty-five super-giant fields, with remaining proven reserves of more than 1 tcm (Groningen in the Netherlands and Troll in Norway). Norway accounts for about half of ultimate European resources.

For several years, the reserves-to-production ratio has been relatively stable at about 20 years despite rising production in the North Sea. Major upward revisions to reserves have been made since the end of the 1980s, most often through better assessments of existing fields. Geological

Table 3.13: **OECD Europe Proven Gas Reserves and Undiscovered Resources** (bcm)

	Proven reserves (on 1 January 2001)	Undiscovered gas resources (mean, on 1 January 1996)
Netherlands	**1,680**	**242**
Norway	**4,017**	**5,180**
United Kingdom	**760***	**662**
Others	**873**	**4,647**
Total	**7,330**	**10,811**

* at 1 January 2000

Sources: Reserves – UK, DTI (2000), others: Cedigaz (2001); Resources – USGS (2000).

knowledge of gas basins is well advanced in the region. However, it is estimated that very significant gas potential still exists in the North Sea, particular on the little-explored Norwegian Continental Shelf. Cedigaz estimates remaining ultimate gas resources in Europe at 13 to 16 tcm.

According to a recent study by ENI/IFP on behalf of the European Commission, remaining natural gas resources in the North Western Continental Shelf (NWECS) amount to 8.59 tcm, of which 3.12 tcm have not yet been discovered and 2.24 tcm are in field developments not yet approved.[33] Including onshore remaining reserves, mainly in the Netherlands, Germany and Italy, Europe's total remaining resources come to 10.8 tcm. These resources would allow western Europe to continue producing 60% of its total requirements over 30 years. But the challenge is to produce that gas cheaper than external supplies. This will require new technologies or technical improvements as the remaining North Sea reserves are becoming more difficult and costly to produce. Four main factors will affect development costs and therefore production prospects:

- In mature areas, future developments will involve smaller fields.
- A large proportion of undiscovered reserves are thought to be located in new areas, far from markets or in deep waters such as the Norwegian Sea and the Barents Sea.
- One potential source of additional supplies is high-pressure/high-temperature reservoirs and fields containing a large amount of liquids.
- Although new fields will be more expensive to develop, some fields contain a high proportion of condensates. Their development will be accelerated as they become more lucrative than dry-gas fields. This could contribute to lower gas-development costs.

Norway

The Norwegian Petroleum Directorate (NPD) estimates recoverable gas resources in Norway at 7.0 tcm at the beginning of 2001.[34] Norway's three main basins account for 93% of reserves: the North Sea (3.4 tcm), the Norwegian Sea (2.3 tcm) and the Barents Sea (0.9 tcm). The North Sea has already been well explored and can be considered a mature area. By contrast, exploration in the Norwegian Sea and especially the Barents Sea has been limited.

33. ENI/IFP (2001).
34. NPD (2000).

The NPD and Cedigaz put proven gas reserves at 4 tcm at the start of 2001. Both estimates have increased by around 200 bcm compared with the beginning of 2000. This increase came from an upward revision in the deepwater Ormen Lange Dome area, now estimated by the NPD at 200 to 400 bcm. The USGS's mean estimate of 5.2 tcm for undiscovered resources is probably reliable as there has been very little exploration of the Norwegian Continental Shelf, which spreads over 1 million square metres.

Marketed production reached an estimated 52 bcm in 2000, almost all of it exported. An additional 40 bcm was re-injected to enhance the recovery of oil or used to run generators and compressors offshore. Production has more than doubled since 1990, thanks mainly to the development of the massive Troll field, which now accounts for around 40% of total Norwegian gas output. Production will continue to rise in the short to medium term as new fields are developed. Contracted supplies are due to plateau at about 75 bcm/year from around 2005. But there is scope for further increasing sales, even without adding capacity to the offshore-pipeline network. Current pipeline capacity of 86 bcm/year (once the Vesterled line linking Heimdal to the Frigg line is completed in late 2001) could probably be increased with additional compression to 100 bcm/year. A new link to the Baltic countries, which is currently under consideration, could further boost capacity.

The Government's policy is to develop its gas reserves progressively as the country's oil reserves decline. But the rate at which fields are brought onstream depends largely on demand in the key European markets, including the United Kingdom. Ormen Lange and Kristin in the Haltenbank area of the Norwegian Sea are the fields next in line for development to meet new demand.[35] Field-development costs are likely to be high, adding to the cost of piping gas ashore. The European Commission recently estimated that it would cost on average $2.75/Mbtu to supply Norwegian gas from new developments to North Europe.[36] The Observatoire Mediterraneen de l'Energie (OME) estimates the cost of supply at $2/Mbtu for North Sea satellite fields ($1.30 for production), $2.20 for the Norwegian Sea ($1.20 for production) and $3.34 for the Barents Sea ($1.20 for production).[37]

35. The construction of the country's first gas-fired power station, scheduled to come on line in 2004, will be fed by gas from Haltenbank.
36. Cited in European Gas Markets (16 March 2001).
37. OME (2001).

United Kingdom

The UK Department of Trade and Industry (DTI) estimates remaining proven gas reserves at 0.76 tcm as of 1 January 2000 (1.195 tcm as of 1 January 2001 according to Cedigaz), probable reserves at 0.5 tcm and possible reserves at 0.49 tcm.[38] Potential additional resources are estimated in the range 75 to 245 bcm and undiscovered recoverable gas resources at 0.355 to 1.465 tcm, most of them located in the West of Shetland, the Southern North Sea, the Irish Sea and the Celtic Sea Basin. The USGS's mean figure for undiscovered resources, 0.66 tcm, appears to be very conservative since some areas are still poorly explored. With cumulative production of 1.41 tcm to the end of 1999, the DTI estimates total remaining resources to lie in the range of 1.19 to 3.46 tcm. Production was 115 bcm in 1999, giving a R/P ratio of less than 7 years – compared to around 11 years in 1990. This decline reflects the impact of market liberalisation and the diminishing importance of long-term supply contracts. The new situation has have given producers a strong incentive to explore for, appraise and develop fields on a "just-in-time" basis and to accelerate production from fields as they are brought on stream.

The further development potential of the UK Continental Shelf (UKCS) lies mainly in small fields located near existing infrastructure in the Southern and Central North Sea. These developments will depend heavily on innovative technology, such as extended-reach drilling, and on the integration of the extensive infrastructure already in place for existing fields. There may also be a shift to fields located further north and west of Shetland. How many of the fields that are discovered will actually be developed in the coming years will depend largely on the success of efforts to lower costs and the gas price. Drilling of exploration and appraisal wells slumped after the collapse of oil prices in 1999 and has not yet fully recovered, despite the rebound in prices. How soon UK production will peak will depend on how many fields are deemed economic and on the rate of growth of demand – especially in the power sector. Increased power-sector demand increases the average industry load factor and, therefore, reduces the need for production swing[39] and improves cashflow. Production is currently expected to peak at around 120 bcm/year at some point between 2005 and 2010. Depending on demand trends, the United Kingdom could become a net importer of gas by 2005.

38. DTI (2000).
39. A contractual commitment allowing a buyer to vary up to a specified limit the amount of gas it takes on a given day.

Netherlands

The Netherlands still has large quantities of low-cost extractable gas. Gas reserves are estimated at 1.7 tcm. They have fallen much less than expected over the last 30 years. The giant Groningen field accounts for 64% of the total (1.1 tcm). Undiscovered resources are estimated by the USGS at 242 bcm – a little lower than the estimate of 325 bcm made by the national transmission company, Gasunie. Production totalled 73 bcm in 2000.

Slower exploration efforts in recent years have prompted the Minister of Economic Affairs to change the oil and gas regime, in order to stimulate more offshore exploration. The Government is also actively pursuing a "small-gas fields' policy to discover, develop and operate smaller fields to improve the long-term management of its natural gas resources. By the beginning of 1999, 341 small gas fields had been discovered with total reserves of 600 bcm. Most of these fields have initial reserves of less than 4 bcm. Gasunie can accept production from small fields with high load factors by adjusting its purchases from the large Groningen field. Production from small fields has been running at 50 to 55 bcm per annum in recent years and it is expected that this level will be maintained in the near term. The Gas Act, which came into force in August 2000, requires Gasunie to purchase gas from small fields on reasonable terms and at market prices. Overall production is likely to remain broadly stable over the next decade.

Intra-regional Trade and Imports

Given the limited gas resources in most European countries and the prospect of rising demand, trade between European countries, and imports from outside the region, are expected to continue growing for the next two decades at least. Norway is likely to be the main source of incremental indigenous supply to the United Kingdom and Continental European markets – and possibly to Central and Eastern Europe countries too. But Norwegian supply is unlikely to be sufficient to meet the expected growth in demand. The *WEO 2000* Reference Scenario projects demand to grow by an average 2.8% per year from 1997 to 2020. This implies a significant expansion in gas imports of gas from non-European suppliers, since indigenous production is projected to remain flat.

In the near term, demand is well covered by long-term contracts that provide for increasing imports. The European Commission estimates that EU countries' current import contracts can meet internal needs, over and above indigenous output, up to 2006, when total EU imports are projected to reach 317 bcm, up from 221 bcm in 2000.[40] But the degree of coverage varies markedly between countries. National gas companies in some countries, notably Italy, have over-contracted for gas for 2005. Others, including Portugal, will need to contract for additional supplies to meet their projected needs. Trading and physical swaps between them could offset part of these imbalances. Beyond 2006, as gas-to-gas competition develops, short-term contracts are expected to meet a growing proportion of each country's gas requirements. Moreover, the recent rise in oil and gas prices has raised the possibility of importing gas from more distant locations by pipeline or in the form of LNG. It has also boosted the prospects of higher production from the NWECS.

The pattern of inter-regional trade that ultimately emerges for a given level of demand and price will depend on a range of supply-side factors. The most important are: comparative supply costs, the degree of competition, government policies on supply diversity and perceptions of investment risk.

Cost is crucial. Figure 3.21 describes graphically the results of an IEA analysis of indicative cost levels for supplies from selected sources for delivery to European borders around 2010. These numbers should be treated with caution. Actual supply costs could differ significantly, depending on the detailed design of each project. Costs are also highly sensitive to the assumed discount rate. The results, nonetheless, give a broad indication of the cost ranking of the main supply options.

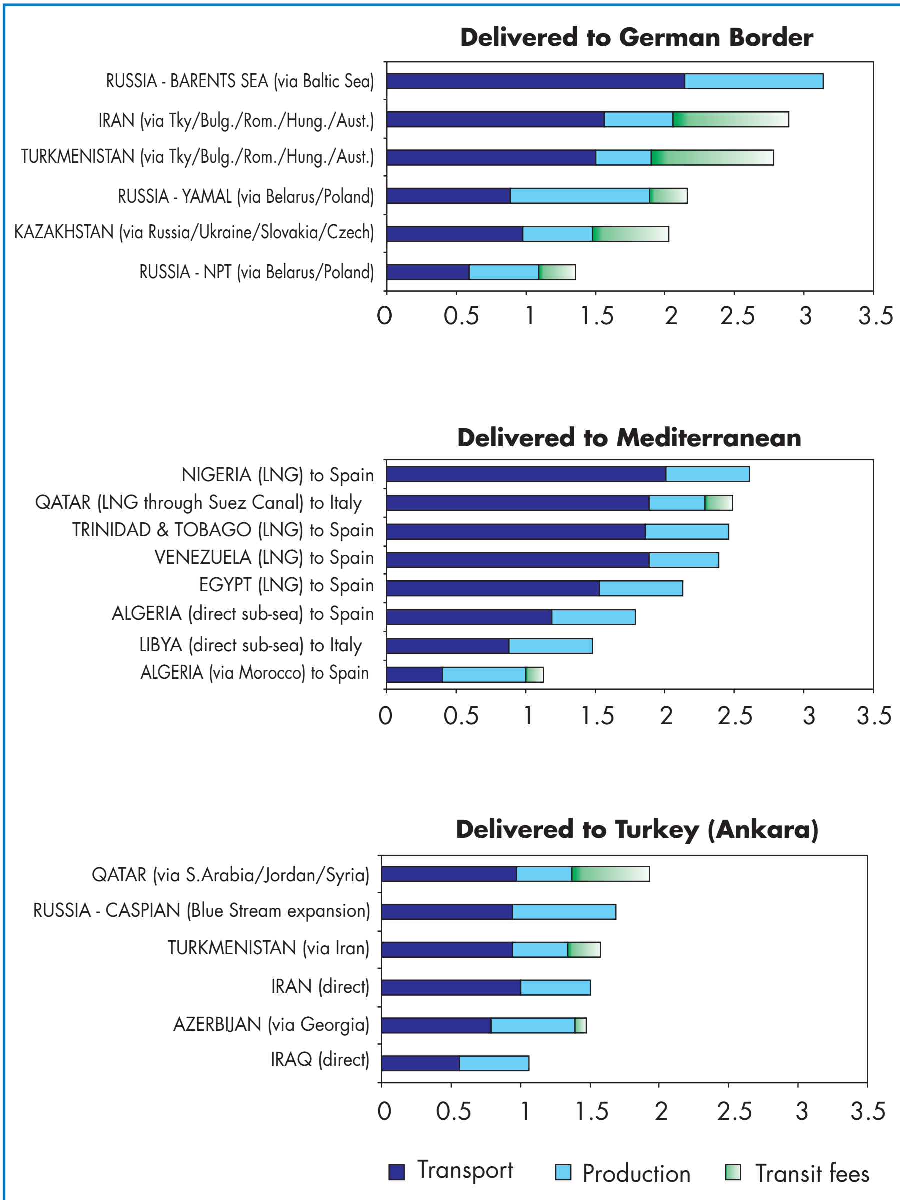
For the purposes of this analysis, production costs, which do not include taxes or royalties, and transit charges, which are assumed to be a function of the number of countries crossed and distance, are notional. Pipeline and LNG cost estimates are based on generic capital and operating cost estimates that take no account of project-specific factors, a 10% discount rate and 30-year asset lives. Utilisation rates of 90% for LNG liquefaction and 85% for pipelines are assumed. The following assumptions relate to capacity and transport routes and modes for each supply source:

- *Algeria to Spain:* 9 bcm/year of additional capacity is assumed for the existing Maghreb-Europe line via Morocco with increased compression; capacity of 12 bcm/year is assumed for the new sub-sea line.

40. Cited in European Gas Markets (16 March 2001). EU countries are all included in OECD Europe and account for 87% of the latter region's gas consumption.

Figure 3.20 : **Potential Incremental Gas-Supply Options for Europe**

Figure 3.21: **Indicative Costs For Potential New Sources of Gas Delivered to Europe, 2010** ($/Mbtu)



Source: IEA analysis.

- *Azerbaijan to Turkey:* New offshore and onshore 15 bcm/year lines from the Shah-Deniz field via Georgia to Ankara.
- *Iraq to Turkey:* A new 25 bcm/year line from the Kashim Al Ahmar/Gilbat fields to Ankara.
- *Iran to Turkey and Germany:* A new 25 bcm/year line from the South Pars field.
- *Kazakhstan to Germany:* A new 25 bcm/year line from the Kashagan field via Russia and Ukraine.
- *Libya to Italy:* A new 11 bcm/year sub-sea line.
- *Qatar to Turkey:* A new 25 bcm/year line from the North Field via Saudi Arabia, Jordan and Syria.
- *Russia, Barents Sea to Germany:* A new 25 bcm/year line from the offshore Shtokmanovskoye field across northwest Russia and the Baltic Sea.
- *Russia, Caspian (Blue Stream expansion) to Turkey:* New 16 bcm/year parallel lines across the Black Sea section, with supply from the Astrakhan field.
- *Russia, Nadym-Pur-Taz (NPT) to Germany:* A new (2nd) 25 bcm/year line from the Torzhok compressor station northeast of Moscow to the German border.
- *Russia, Yamal to Germany:* A new 1,000-kilometre, 25 bcm/year line to the existing NPT pipeline system plus a new line from Torzhok to the German border.
- *Turkmenistan to Turkey and Germany:* A new 25 bcm/year line from the Amu-Darya basin traversing Iran.
- *Egypt, Nigeria, Qatar and Venezuela LNG to Spain and Italy:* Greenfield 6.6 Mt/year capacity projects. Qatari LNG is shipped through the Suez Canal.

Our analysis suggests that the lowest cost potential sources of incremental gas from outside Europe are to be found in North Africa, notably Algeria. Expansion of the existing Maghreb-Europe Pipeline system could enable new gas to be delivered to Spain at just over $1.50/Mbtu (not including production taxes and royalties). Egypt is the cheapest source of LNG for delivery to Spain, thanks to the short shipping distance involved. LNG could probably also be supplied to the Mediterranean from Latin America or Nigeria at about $2.50/Mbtu.

Russian gas from the Nadym-Pur-Taz region delivered to the German border is estimated to cost under $1.50/Mbtu with the construction of a new line from Torzhok to Germany via Belarus and Poland. Caspian and

Middle East supply options are more expensive, although higher throughputs than are assumed in our analysis would give lower unit costs thanks to economies of scale.[41] Russian gas from Yamal and the Barents Sea are among the most expensive options for Northern Europe. Costs are potentially much lower for delivery to Turkey due to the shorter distances involved.

OME recently carried out a similar cost analysis on behalf of the European Commission, including estimates of volumes available for supply to European Union countries.[42] Their cost estimates are broadly in line with our own, although the cost-ranking of some supply options is different. OME estimates that, in 2010, around 60 bcm of additional gas could be supplied to the borders of European Union as it is now at under $2/Mbtu and almost 170 bcm at less than $3/Mbtu.

In practice, supplies are unlikely to be developed in strict cost-order since factors other than cost influence buyers' choices of upstream projects:

- Political risk is a major consideration for many of the more distant supplies, particularly those whose gas must transit through several countries deemed to be politically unstable. In recent years, occasional disruptions to Russian gas supplies through Ukraine to Western Europe and Turkey because of non-payment by Ukrainian gas buyers have highlighted these risks. Such concerns continue to undermine projects for high-capacity pipelines to bring gas from the Middle East and the Caspian region.
- Potential or actual government limitations on the proportion of imports from single suppliers may significantly alter supply patterns. In Spain, for example, imports from a single country are legally capped at 60% of total imports. This means that LNG is likely to be favoured over increased piped supplies from Algeria, which currently supplies most of Spain's gas.
- Competition in downstream and upstream markets, on the other hand, will increase the emphasis on seeking out the cheapest sources of supply, to the extent that the constraints mentioned above allow.

On balance, incremental European gas import needs are likely to be met by increased piped supplies from the two main existing suppliers, Russia and Algeria, and a mixture of piped gas and LNG from other

41. Gas lifted by non-European buyers en route would also help to lower the unit cost of gas delivered to European borders.
42. OME (2001).

existing or emerging suppliers. The latter will probably include Libya (via pipeline), Nigeria, Trinidad and Tobago, Egypt and possibly Qatar (LNG). Venezuela may also emerge in the longer term as a bulk supplier of LNG, while spot shipments of LNG from other Middle East producers may also increase if a global, short-term market in LNG develops. LNG, both under long-term contracts and spot purchases, could play a much more important role in supplying the European gas market if supply costs continue to fall and the availability of Russian gas is less than expected (either because production from existing fields declines faster or because domestic consumption recovers more strongly).

Transition Economies

Market Overview

Russia, with a long tradition of gas production and exports, dominates the gas industry in the transition economies.[43] Tremendous reserves of gas remain in Russia's large producing fields as well as in smaller fields adjacent to the super-giants. Other FSU countries in Central Asia and the Caspian region also hold substantial reserves, which could be used to augment supply to local and export markets.

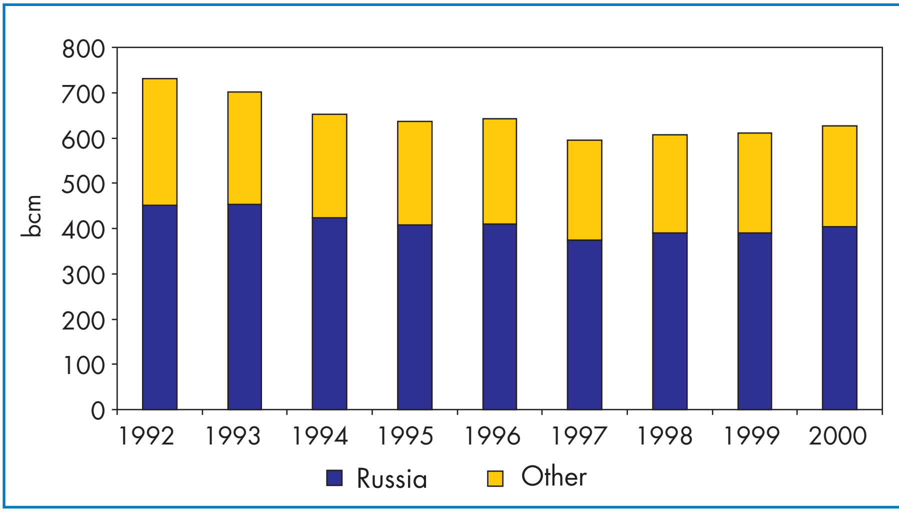
Russian gas production fell from 640 bcm in 1990 to 584 bcm in 2000, due to under-investment in the upstream and a slump in domestic demand following the break-up of the Soviet Union (Figure 3.22). Gas fell less, however, than did other fuels. Exports to European countries have nonetheless continued to increase and now account for 37% of total Russian output.[44] Gazprom is the dominant producer in Russia. Through its subsidiary company, Gazexport, Gazprom is the sole exporter of Russian gas to western Europe. At present, other transition economies account for only 138 bcm (19%) of the region's total production of 723 bcm in 2000. Uzbekistan is the largest producer after Russia (56 bcm).

Reserves and Resources

Cedigaz estimates proven gas reserves in the transition economies at 58.2 tcm at the beginning of 2001 – equivalent to 36% of global reserves and the joint largest of any world region with the Middle East. According to the USGS's latest survey, the region contains 37.5% of world gas

43. The successor states of the FSU and Central and Eastern Europe.
44. Russia imports around 37 bcm from other FSU countries, mainly Turkmenistan.

Figure 3.22: **Natural Gas Production in the Transition Economies**



Source: IEA (2001a).

Table 3.14: **Transition Economies' Proven Gas Reserves and Undiscovered Resources** (bcm)

	Proven reserves (at 1 January 2001)	Undiscovered gas resources (mean, at 1 January 1996)
Russia	48,100*	33,075
Azerbaijan	1,370	1,909
Kazakhstan	2 ,323*	2,045
Turkmenistan	2,900	5,878
Uzbekistan	1,750	426
Other FSU	1,346	779
Eastern & Central Europe	419	223
Total	58,208	44,335

* As of 1 January 2000.
Sources: Reserves – Cedigaz (2001) for Azerbaijan, Turkmenistan, Uzbekistan, other FSU and Eastern & Central Europe; IHS (2001) for Kazakhstan; and Gazprom (2001) for Russia; Resources – USGS (2000).

resources. The largest amount of undiscovered hydrocarbon resources is in the richest petroleum province, the West Siberian basin in Russia.

Estimated undiscovered gas resources are dramatically lower than in the USGS's previous assessment in 1994, by 32 tcm. The northern West

Siberian basin, including the South Kara Sea, and the Barents shelf account for most of this revision.

Russia

Russian gas reserves stood at 48 tcm on 1 January 2000, according to Gazprom. Cedigaz estimates gas reserves at 46.6 tcm on 1 January 2001. These figures include proven and probable reserves. Western Siberia has 37 tcm of reserves, or 77% of the total, and the Arctic Shelf, principally the Barents and Kara Seas and the Sakhalin Shelf, have 4 tcm. Gazprom has licences for the exploitation of 34 tcm of proven and probable reserves representing 71% of the total. Some 60% of the company's reserves are concentrated in a small number of fields in the Nadym-Pur-Taz region of Western Siberia.

Undiscovered resources are estimated by USGS at 33 tcm. According to Gazprom, initial ultimate resources are in the range of 180 to 200 tcm. There are also large resources in the Russian sector of the Caspian region and adjacent coastal areas, Western North Caspian basin and Astrakhan. This region has some 1.5 to 2 tcm of gas, mainly in the Astrakhan field. The Russian sector of the Caspian is little explored. USGS puts the undiscovered potential of that area at 1.04 tcm.

Gas reserves declined somewhat during the 1990s, largely because exploratory activity fell off sharply. Even on the basis of conservative estimates of proven and probable reserves, however, Russian production would be maintained for more than 40 years at 2000 levels.

Central Asia/Caspian Sea

Azerbaijan's proven gas reserves are estimated at 1.4 tcm. They have been revised upward, as drilling activity on the Shah-Deniz structure – by far the largest gas field in Azerbaijan, with 700 bcm of reserves – has yielded high flows. The USGS's mean figure for undiscovered resources, 1.9 tcm, looks reasonable, given the number of deepwater gas-prone structures that remain undrilled. The Azeri state oil company, SOCAR, estimates that Azerbaijan's total gas resources could amount to 3 to 4 tcm in the offshore Apsheron area, which is operated by Chevron, and to 1 tcm in the offshore Shah-Deniz area.

Proven gas reserves in *Kazakhstan* are estimated at 2.3 tcm. Gas reserves are split among two major fields: the Karachaganak field with recoverable gas reserves of 1.3 tcm and the Tengiz associated-gas reserves (460 to 690 bcm). The recent offshore-oil discovery at Kashagan is likely to boost gas reserves by a good deal. It may contain an additional 0.5 to

1.5 tcm of associated-gas reserves. The USGS estimates undiscovered gas resources at 2 tcm.

In *Turkmenistan*, proven gas reserves are estimated at 2.9 tcm. Many Turkmen gas fields would have considerable upside potential if they were developed in a modern way. USGS' mean estimate of 5.8 tcm of undiscovered resources looks very high. Turkmenistan has been well explored, although there are still under-explored regions such as the South Caspian and the left bank of the Amu-Darya.

Uzbekistan, which has 1.75 tcm of proven reserves, is the only post-Soviet republic that succeeded in increasing its production after independence. USGS estimates undiscovered resources at 425 bcm, which reflects very high exploration maturity.

Prospects for Production

Russia[45]

The main source of uncertainty for Russian gas production is the rate of decline in the output from the Urengoy, Yamburg and Medvezhe fields in the Nadym-Pur-Taz region of Western Siberia. These fields currently account for over 75% of national output. In view of the very high decline rates forecast for the region, a great deal of new capacity has to be brought on stream over the next two decades if production levels are to be maintained. Nadym-Pur-Taz production, which is expected to drop by more than 75% between now and 2020, according to the official National Energy Strategy, is expected to be supplemented first by Barents Sea gas, from the offshore Shtokmanovskoye field. Then – after 2015 – the shortfall will be replaced by production from the Yamal Peninsula fields. With lead times of five-to-seven years to bring large fields in the Nadym-Pur-Taz region in Western Siberia into production, development plans need to be set well ahead of time.

There is considerable uncertainty about how rapidly production from existing fields will decline. Projections by Gazprom and the Russian Government foresee a sharp acceleration in decline rates. This may reflect damage inflicted on reservoirs through precipitate production increases during the Soviet era. But, with appropriate investment in production infrastructure, the decline in output has been staved off at the Medvezh'ye field. It is likely that the same programme can be implemented at the

45. This section and the later discussion of export prospects draw on the gas chapter of the recent IEA review of Russian Energy Policies (IEA, 2001b).

Urengoy and Yamburg fields. The key judgement is whether the required investments will be made; that will depend on the expectation of adequate returns on investment.

If the Urengoy and Yamburg fields do decline as projected in the Government's Energy Strategy, nearly 300 bcm of new production capacity would be needed in the next 20 years to meet expected demand. Future supply developments will depend on the ability and willingness of customers – domestic[46] and foreign – to pay high enough prices needed to support new investments. Heavy foreign investment and technology will undoubtedly be needed, not only for new-field developments and the building of transportation infrastructure, but also to deal with the exceptionally difficult geological and climatic conditions. Although the country is widely perceived as a high-risk place to do business, the enormous gas potential is beginning to attract foreign investors through Production Sharing Agreements.

One option for the Russians would be to open up new West Siberian fields where production costs will be higher than for the existing super-giants. Zapolyarnoe, with 3.4 tcm of reserves and a production plateau of 100-to-150 tcm per year is the next giant field scheduled for exploitation. Overall costs of gas delivered to customers depend crucially on transportation costs. These, in turn, depend on the fields' proximity to existing transmission lines. Production costs for Zapolyarnoe might amount to as much as 50 cents/Mbtu.[47] New fields located near to fields already in production in Nadym-Pur-Taz require new pipelines as long as 300 kilometres to connect them to the existing transmission system. These are far more economically attractive than larger, but more remote, fields on the Yamal Peninsula. These might cost as much as \$1/Mbtu to develop and would require much longer transmission lines across more difficult terrain. As a result, development of the Yamal fields is not expected before 2015.

Outside Siberia, the most promising production prospect is the Shtokmanovskoye field, in the Barents Sea, with 3 tcm of reserves, although gas from this field will require a very long pipeline to Russia and European markets (Figure 3.23). The Government estimates that it would cost a third less to develop the Shtokmanovskoye field than the super-giant fields on the Yamal Peninsula. But this may be an optimistic assessment, given that the field is located 550 kilometres offshore in ice-floe-prone water. In European Russia, the only other large new fields, which could be

46. Domestic customers currently pay subsidised prices. See IEA (1999), Chapter 6.
47. See OME (2001).

further developed, are around Astrakhan. Further development of the Astrakhan field itself could feed gas into the Blue Stream pipeline to Turkey. In addition, as many as 500 marginal fields could be developed. Although most of these fields contain less than 20 bcm of reserves and many have low flow rates, they are much closer to markets and many of them could have low production and transmission costs. But domestic price reform is essential for these fields to become attractive to investors.

While reserves are clearly adequate to meet projected domestic demand and to support higher exports over the next two decades, developing those reserves will depend on whether investors can make adequate returns. Given the current economic and business environment in Russia, the prospect for such returns is, at best, unclear. Major uncertainties surround prices, payments, terms of payment, taxation and the new regulatory framework.

Central Asia/Caspian Sea

Production in the Central Asia/Caspian region is focused on Turkmenistan. Turkmen production has slumped from a peak of over 80 bcm in 1990 to about 13 bcm in 1998, recovering to 23 bcm in 1999 and an estimated 47 bcm in 2000, thanks to new export deals with Russia and the Ukraine. Turkmen exports to Iran remain stagnant at around 2 to 3 bcm/year. Production prospects for Turkmenistan and other countries with reserves in the region will depend largely on their access to export markets. Projects to export gas to Europe and Asia are hindered by long distances, political instability and competition form other supply sources.

Intra-regional Trade and Exports to Europe and Asia

Russian gas deliveries to the FSU and Eastern and Central Europe have fallen off since the break-up of the Soviet Union, due to a combination of factors. Of these, the most important have been reduced economic activity throughout the region and the inability of many export customers, largely in the FSU, to pay. The Russian Government does not expect exports to other FSU countries to increase greatly in the medium term. This may reflect partly an expectation that Central Asian exporters will supply more gas to other FSU countries, transiting Russia. This might be a more economically attractive option for Russia than developing new indigenous gas fields. Turkmen exports through the Russian system to the Ukraine and other FSU countries may continue to rise in the near term, especially if they are needed to offset any shortfalls in Russian gas production.

Figure 3.23: **Former Soviet Union Natural Gas Resources and Infrastructure**

The only transition countries to export gas to countries outside the region are Russia, which exports to several European countries, and Turkmenistan, which exports to neighbouring Iran. Preliminary data show that Gazprom delivered 117 bcm to OECD European countries in 2000. By 2008, Gazprom is committed to deliver 200 bcm under long-term contracts, some of which run through to 2025.[48] Virtually all currently contracted volumes are long term. The rest are covered by annual contracts. Gazprom does not intend to sign any additional long-term contracts with European customers until 2008 at the earliest. This policy appears to be motivated in part by the belief that European concerns over excessive dependence on Russian gas will, in any case, rule out more exports.

Under already signed contracts, exports to Europe will probably increase strongly until 2005, but Gazprom expects them to grow more gradually over the following fifteen years. Gazprom projects a 50 bcm increase in exports to Europe from 2000 to 2005 and a 20 bcm increase from 2005 to 2020. Whether any more gas can be exported to Europe will depend on several factors, including the course of demand and prices and the impact of competition on pricing. Other factors include the possibility that competition may trigger the emergence of new exporting companies independent of Gazprom. The cost of developing new reserves and building new pipelines will affect producers' ability to finance new projects. The impact of price reform on demand trends in Russia will also play a major role.

Box 3.7: **European Gas Liberalisation and Russian Exports**

The liberalisation of European gas markets, which threatens to undermine the traditional long-term take-or-pay contractual structure, will clearly affect Russian exports to Europe. While long-term contracts will probably remain the backbone of the industry, traditional pricing of gas against alternative fuels, principally oil products, is likely to be replaced by increased reliance on spot-price indexation. Competition is also expected to drive prices down, certainly from the oil-linked heights they reached in late 2000 and

48. This assumes that long term contracts for around 25 bcm/year of gas which expire in the period 2000-2008 will be prolonged.

early 2001. Some contractual clauses such as re-sale rights may be softened, and price re-negotiations may become more frequent.

These trends could increase the financial risk to investors in such mega-projects as the development of the Yamal gas fields, and make financing more difficult. Reducing risk through enhanced dialogue and co-operation between Russian and European authorities could help offset this factor. The EU-Russia energy partnership initiative, launched at the Paris Summit in October 2000, was one step in this process. The ratification of the Energy Charter Treaty and the signing and subsequent ratification of the Energy Charter Transit Protocol would provide a legal foundation for setting tariffs and handling disputes over gas in transit through FSU countries. Ultimately, joint marketing and funding arrangements between downstream and upstream companies may prove necessary, although the European Union would have to approve such arrangements. These issues will be of particular concern after 2010, when new large-scale upstream investment will be needed.

A major strategic objective for Gazprom is to diversify its export-pipeline routes away from Ukraine because of commercial and logistical concerns about transiting gas through that country. A pipeline via Belarus to Poland and on to Germany, part of the eventual Yamal system, was commissioned in 1999 and another is planned. In addition, a link from that line, from Poland to Slovakia, which would bypass Ukraine and allow continued full use of the existing Slovak-Czech pipeline network, is under consideration. An alternative to building a second Belarus-Poland line would be a line running from a coastal point north of St Petersburg to Northern Germany, supplying Finland and Sweden *en route* (known as the North Transgas project). The gas for this line could be supplied from Nadym-Pur-Taz, from Yamal or from the Shtokmanovskoye field.

The Blue Stream pipeline to Turkey, one of the fastest-growing gas markets in Europe, is also intended to avoid transit problems with Ukraine, which have disrupted exports periodically in recent years. Blue Stream – a 50:50 joint venture between Gazprom and Italy's ENI – involves the laying of two 374-kilometre pipelines across the Black Sea from the Russian coast to northern Turkey and an onward land pipeline to Ankara. The sub-sea section of the parallel 24-inch lines will be laid at a depth of 2,150 metres – deeper than any pipeline in the past. It will have an ultimate capacity of 16 bcm/year. Construction is underway and gas is planned to start flowing by 2002.

Asia could be an alternative export outlet for gas from Eastern Siberia and the Russian Far East. The following projects are currently under consideration:

- LNG and/or pipeline exports based on gas from fields discovered offshore Sakhalin Island. The Sakhalin 1 and Sakhalin 2 joint ventures – both under Production Sharing Agreements – have gas reserves large enough to support LNG or pipeline projects to Japan, China or Korea. Issues to be decided include whether the gas will be moved by pipeline or as LNG[49] and whether project developers will build their own infrastructure or will share joint facilities. Markets and buyers for the gas must be identified. Pipeline exports may be delayed, however, by insufficient demand and high onshore pipeline costs in Japan.
- The Kovykta gas field near Irkutsk, which would require a major pipeline to be built from the field to China with a possible extension to Korea. The project may be delayed if competing regional projects, including Sakhalin and the West-East China line, get earlier approval.
- Large gas fields in the Sakha Republic, which may be adequate to support an export project to China or Japan, or possibly integrated with the Irkutsk project. But, given the distance of these reserves from export markets and the technical difficulty of the terrain, early development seems unlikely.
- A pipeline from West Siberia to China, connecting with the planned West-East Pipeline.

The prospect of exports from Central Asia and the Caspian region to either Europe or Asia are considerably more uncertain than are those for Russian exports. The long distances and large capital expenditures involved, political instability in neighbouring regions and disputes over the legal status of the Caspian are major hurdles to the development of pipeline projects in the region. Azerbaijan recently announced a deal to export gas from the Shah-Deniz field to Turkey at a plateau rate of 6.6 bcm/year from 2004. The gas would flow through a new line to be built by a BP-led consortium. Exports of gas from Kazakhstan or Turkmenistan to Europe

49. Sakhalin-1 is currently considering a pipeline to Japan, while Sakhalin-2 is studying a 9 Mt/year LNG liquefaction terminal.

would probably require the construction of new lines to connect up with existing systems in Russia or Turkey.

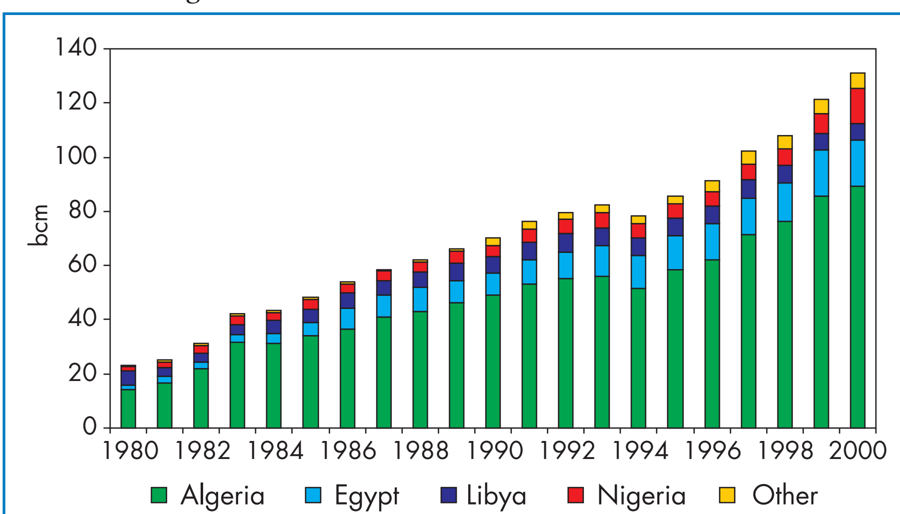
Several projects to export gas from Turkmenistan to Turkey have been mooted. The proposed Trans-Caspian Gas Pipeline, with a capacity of 28 bcm/year and a length of 1,600 to 2,000 km, would be routed across the Caspian Sea and Azerbaijan. Interest in the project has waned since the Azerbaijan export project mentioned above was finalised. An alternative plan to export Turkmen gas via Iran has also been proposed. This is unlikely to proceed in the near term because of US sanctions against Iran, the high cost of the project, the need for substantial sales to Turkey and Iran's competing export ambitions. Turkmen exports to northern Iran, however, look set to rise to 8 to 10 bcm/year by 2005 with the expansion of the capacity of the existing line and the resolution of contractual and payment disputes.

Africa

Market Overview

Africa has large natural gas resources. The biggest resources are found in Nigeria (around 7 tcm) and Algeria (5 tcm). Exports account for a large percentage of production, as local demand is limited. Economic and

Figure 3.24: **Natural Gas Production in Africa**



Source: IEA (2001a).

demographic growth in the region and increasing demand from Europe and North America are expected to underpin the development of resources in the coming decades.

The use of gas in Africa's commercial energy market and per capita natural gas consumption are very low (75 cubic metres/capita compared to the global average of 417 cubic metres/capita in 2000). The largest gas-consuming African countries are Algeria and Egypt, both big producers, which account together for 68% of total African gas use. Gas consumption is projected to grow at an annual average rate of 4.35% per year from 1997 to 2020. Intra-regional trade is very small.

Resources and Production Prospects

Africa's proven gas reserves amounted to 11.7 tcm at the beginning of 2001, or 7% of the world total. Exploration over the last 20 years has augmented the confirmed gas reserves of the region substantially. But the continent is still relatively under-explored and its gas potential has not been fully appraised. Four countries, Algeria, Egypt, Libya and Nigeria, account for 91% of regional reserves. However, 18 other countries have made gas discoveries on their territory. Recently, major discoveries were made in Egypt, offshore Angola and Congo.

Table 3.15: **African Proven Gas Reserves and Undiscovered Resources** (bcm)

	Proven reserves (at 1 January 2001)	**Undiscovered gas resources (mean, at 1 January 1996)**
Algeria	4,250	1,386
Egypt	1,444	578
Libya	1,325	597
Nigeria	3,610	3,487
Others	1,073	4,125
Total	11,702	10,173

Sources: Reserves – Cedigaz (2001); Resources – USGS (2000).

The largest African gas producer is Algeria (89.3 bcm in 2000), followed by Egypt (17.1 bcm), Nigeria (12.9 bcm) and Libya (6.2 bcm). All these countries, except Egypt, export most of the gas they produce to Europe. Rising domestic demand, driven by high population growth and industrialisation, is expected to underpin an expansion in production capacity. Expansion will also be spurred by the export ambitions of current exporting countries and the emergence of new exporters: Egypt, Mozambique and Angola.

Algeria's proven gas reserves of 4.25 tcm are the largest in the region. The USGS estimates undiscovered gas resources at 1.4 tcm, which seems low since much of the country has not yet been fully explored. The Algerian national oil and gas company, Sonatrach, reported 11 new discoveries in 2000, seven made on its own and four under Production Sharing Agreements with international companies. These discoveries produced additional gas reserves of 23 bcm. Sonatrach needs increasing amounts of gas for re-injection to sustain oil production.

Domestic sales were 23.8 bcm in 2000. Exports to Europe, 65.5 bcm in 2000, are served by two LNG terminals (at Arzew and Skikda) and two pipeline systems (the Maghreb pipeline via Morocco to Spain and the Transmed system via Tunisia to Italy). The gas comes mainly from Hassi R'Mel. Re-injected gas is estimated to amount to almost 90 bcm. BP is currently developing reserves at In Salah in southern Algeria under a Production Sharing Agreement with Sonatrach with production at a plateau rate of 9 bcm/year due to start in 2004. Sonatrach has also signed similar agreements with Petronas of Malaysia and Gaz de France to appraise discoveries and carry out further exploration in the Ahnet Basin south of In Salah. If development of Ahnet reserves goes ahead, a 380-kilometre pipeline to link up with the planned pipeline from In Salah to Hassi R'Mel would need to be built.

In *Egypt*, government policies have stimulated such interest in exploration that proven gas reserves rose to 1.44 tcm at the start of 2001, from 0.9 tcm at the start of 1998. From October 1999 to November 2000, new discoveries boosted reserves by 42%. Egypt's leading gas producer is ENI, through its Egyptian affiliate, IEOC. Together with the state company, EGPC, IEOC is active in the Gulf of Suez, the Nile Delta and the Western Desert regions. BG, another significant producer, has made 16 discoveries since 1997, totalling more than 280 bcm, at its West Delta Deep marine concession. The outlook for production is largely dependent on growth in the domestic market and on export sales to Europe. Several LNG projects are planned.

The lifting of UN economic sanctions against *Libya* and the opening up of its acreage to foreign companies have boosted Libyan exploration activity. The USGS estimates the country's undiscovered gas resources at 597 bcm, which seems very low. Proven reserves are 1.3 tcm. Exports –

entirely to Spain from Libya's sole liquefaction plant at Marsa El Brega – accounted for 0.8 bcm of the country's output of 6.2 bcm in 2000. While foreign companies will continue to emphasise expanding Libyan oil reserves and production, more attention is expected to be paid to the country's largely untapped gas potential. Proximity to European markets is an attraction for international investors. Libya has also added a gas clause to its standard exploration and production-sharing agreement which allows companies to market their gas discoveries for export. Agip/ENI has signed an agreement with the Libyan National Oil Company for the joint exploitation of offshore and onshore reserves in the West. This gas will be for both export (8 bcm/year) and domestic use (2 bcm/year) from 2004.

Nigerian proven gas reserves and undiscovered resources are both estimated at around 3.5 tcm, confirming the country's vast gas potential. Around half the proven reserves are associated with oil. Marketed production reached 12.9 bcm in 2000, with 4.5 bcm exported as LNG. Some 4.5 bcm was re-injected and 19.3 bcm was flared. The start-up of LNG exports in 1999 and rising domestic use (in power generation and as a feedstock for NGL plants) has reduced flaring. Exports are set to increase strongly when liquefaction capacity is expanded in 2002. Two more trains are under consideration. Most of the gas that will be supplied to these expansions will be associated gas that is currently flared, so they will not have much affect on gross gas production. The Government plans to stop all gas flaring by 2008.

Intra-regional Trade and Exports

Most of the gas-export projects under development or planned involve exports outside the region – principally to Europe and the United States. *Algeria* will almost certainly retain its position as the largest gas exporter during the next two decades. Exports through the two existing pipeline systems to Spain and Italy are planned to rise, with an additional 10 to 11 bcm/year coming from the In Salah development. There is around 2 bcm/year of spare capacity in the Magrheb pipeline. Capacity could be expanded by 9 bcm/year beyond the current capacity of about 10 bcm/year with additional compression. In addition, Sonatrach and the Spanish company, Cepsa, are investigating the feasibility of building a new pipeline, Medgaz, to carry gas to Europe via Spain. Unlike the Maghreb line, which traverses Morocco, this one would provide a direct deepwater link to Spain. It would probably cost in excess of $2.5 billion and would use the latest deepwater pipeline-laying technology. The project will depend on growth in gas demand in Spain as well as cost considerations. Another link between Algeria and Italy via Sardinia and Corsica has been proposed.

Libya also has ambitions to expand exports beyond their current modest levels. Plans by the Italian firm, ENI, to build a subsea pipeline from Libya to Italy are well advanced. Contracts for 8 bcm per year are already in place, although the line will almost certainly have a larger capacity. *Egypt* is set to become a major LNG exporter in the next few years, with several projects under consideration. The most advanced is a two-train plant being developed by Union Fenosa, with gas to be supplied by the state-owned Egyptian General Petroleum Company. UF has agreed to lift all the output of the first 4 Mt/year train for its own power station needs in Spain. Shell and BG International/Edison are pursuing other projects. A pipeline to export 1.7 bcm/year from the Nile Delta to Israel has also been proposed.

Nigeria is the second-largest African gas exporter, from a two-train 8 Mt/year plant at Bonny Island, which started up in 1999. Exports are set to rise with an additional 3 Mt/year train under construction and due to start up in 2002: the gas will be supplied to Spain and Portugal. Two further trains are under consideration, which could boost capacity by 8 Mt/year from 2005 at the earliest, as well as a new greenfield project. A single-train project is also being considered in *Angola* based on recent offshore discoveries. A pipeline to export Nigerian associated gas to Ghana, Togo and Benin has also been proposed.

Mozambique is set to join the ranks of African gas exporters in 2003. The Governments of South Africa and Mozambique and Sasol have reached agreement on the construction of a 900-kilometre pipeline to South Africa, allowing the development of Sasol's Pande and Temane fields. Some of the gas and pipeline capacity could be used to supply an iron-and-steel project in Mozambique.

Middle East

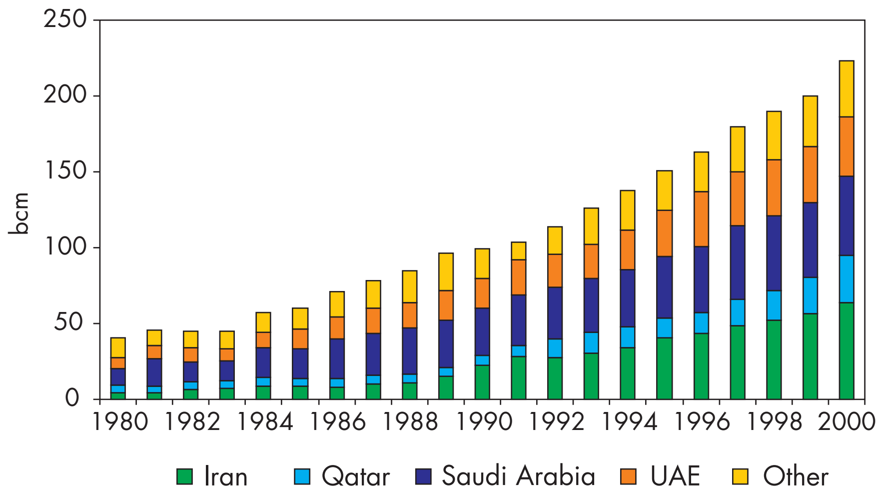
The Middle East is very well endowed with natural gas resources. Iran has the largest resource base in the region (proven reserves plus undiscovered resources) at around 35 tcm. It is followed by Saudi Arabia (25 tcm), Qatar (16 tcm), UAE and Iraq (both around 7 tcm). At present, resources in many of these countries are under-utilised, due to a lack of distribution infrastructure and limited local demand. Production is

Table 3.16: **Planned and Proposed African Export Projects**

Country	Project	Annual capacity	Status
Algeria	Medgaz pipeline to Spain	10-20 bcm	Feasibility study underway by Sonatrach and Cepsa
	Pipeline to Italy	N/A	Under consideration by Edison
	Transmed pipeline expansion	N/A	Expansion of capacity would require additional capacity and/or laying of a new sub-sea line
	Maghreb-Europe pipeline expansion	9 bcm	Increased capacity through additional compression
Libya	Pipeline to Italy	8 bcm+	Subsea line planned with first gas from 2004; 8 bcm of exports already contracted
Egypt	Union Fenosa LNG	8.0 Mt	Two-train plant at Damietta with planned start-up of first train in 2004, second train in 2006/7
	Shell LNG	3 Mt	1- or 2-train plant west of Damietta, planned start-up in 2004
	BG/Edison LNG	3-6 Mt	1- or 2-train plant at Idku, planned start-up in 2004/5
	BP/ENI/EGPC	8 Mt	2-train plant, planned start-up 2004 at the earliest
	Pipeline to Israel	1.7 bcm+	Under negotiation; gas would supply Israel Electric Corporation from 2002/3
Nigeria	Bonny Island LNG, third train	2.95 Mt	Under construction; start-up due in 2002
	Bonny Island LNG, fourth and fifth trains	8.0 Mt	Under consideration; sales to Europe, Brazil and US under negotiation; possible start-up in 2005/6
	Greenfield LNG project	N/A	Feasibility study to be carried out by National Nigerian Petroleum Company and four US producers; possible start-up after 2005
Angola	Angola LNG	4 Mt	1-train project, could supply the US market too; possible start-up in 2005
Mozam-bique	Pipeline to South Africa	10 bcm	Agreement on project reached; start-up due in 2003

Source: IEA databases.

Figure 3.25: **Natural Gas Production in the Middle East**



Source: IEA (2001a)

concentrated in Iran, Saudi Arabia, the UAE and Qatar. Exports account for a large percentage of production.

Iran and Saudi Arabia together account for 60% of the total Middle East gas market. Gas consumption is projected to grow at an annual average rate of 3.8% per year from 1997 to 2020. Consumption is concentrated in the producer countries and intra-regional trade is very small. The rate of development of the region's gas resources will depend on economic and demographic growth and industrialisation as well as demand from Europe and Asia-Pacific.

Resources and Production Prospects

The Middle East is the joint-largest natural gas region by reserves. It contains 58.5 tcm of proven reserves, or 36% of global reserves. Six countries – Iran, Iraq, Kuwait, Qatar, Saudi Arabia and the UAE – hold 97% of total resources in the region. The main area of reserves is in the Persian Gulf, with more than 10 giant structures including the South Pars/North Dome field, which straddles the Iran/Qatar offshore border, with over 10 tcm of proven gas reserves. High gas revenues, caused by the recent increase in oil prices, have led to a rebound in exploration investment for gas. Ultimate gas resources are also very high, at 115 to 136 tcm, according to Cedigaz. Undiscovered resources, as estimated by the USGS, seem very low for most of the countries of the region, with the exception of Saudi Arabia.

Production has risen rapidly in recent years but is still low in relation to reserves. Output will probably continue to rise as the region's oil-dependent economies seek to diversify their industrial activities and exports and meet rapidly rising demand from the power-generation sector. In some cases, governments are seeking to promote greater domestic use of gas to free up more oil for export. Reforms of investment regimes, including the opening up of the oil and gas sector to foreign participation, will be a key factor in how quickly gas-development plans can be realised.

Table 3.17: **Middle East Proven Gas Reserves and Undiscovered Resources** (bcm)

	Proven reserves (at 1 January 2001)	**Undiscovered gas resources** (mean, at 1 January 1996)
Iran	25,800	8,902
Qatar	14,443	1,163
Saudi Arabia	6,012	19,272
UAE	5,991	1,260
Iraq	3,285	3,396
Kuwait	1,480	167
Others	1,521	2,256
Total	**58,532**	**36,416**

Sources: Reserves – Cedigaz (2001); Resources – USGS (2000).

Iran's proven reserves are estimated at around 26 tcm. Undiscovered resources are estimated by the USGS at just under 9 tcm, a low estimate in view of the limited exploration effort to date. Reserves of the offshore South Pars gas field have been substantially upgraded to more than 11 tcm. Iran has recently made several gas discoveries, in particular the Gareh-Dorgh gas field (with estimated reserves of 600 bcm) and the Homa gas field (200 bcm). Production was 63.7 bcm in 2000, all of it consumed domestically. Iran imports a small volume of gas from Turkmenistan. The prospects for production will depend on the need to re-inject gas for secondary-oil recovery, on domestic demand, on funding for gas-field projects and on the development of export sales.

Proven gas reserves in *Saudi Arabia* are about 6 tcm – the fourth largest in the world. Undiscovered resources total 19 tcm, of which 15.8 tcm are not associated with oil. Most of the non-associated gas reserves are located in dispersed, small and deep fields, that are over-pressured and highly corrosive. They will be relatively expensive to develop. Saudi Aramco has intensified exploration for non-associated gas and has achieved good results in this field. The company added about 200 bcm/year to the Kingdom's gas reserves during the 1990s, more than offsetting gas consumption.

Marketed production was 52.8 bcm in 2000, most of it going to the power and petrochemical sectors. Flaring has declined sharply in recent years. The Saudi Government plans to increase domestic use of natural gas by replacing oil with gas in power generation and water desalination, and by increasing the use of gas as feedstock to the petrochemical industry. As part of the Gas Initiative launched in March 2000, three major projects to explore for and develop gas reserves were opened up to foreign investment. These projects cover the South Ghawar oilfield, Shaybah/al-Kidan in the Rub' al-Khali and the Northern Red Sea area. All these regions have good gas-production prospects. The Initiative was prompted partly by delays in expanding the Master Gas System (MGS) – a gas gathering, processing and distribution network, the construction of which started in 1982. The Government plans to extend the MGS pipeline from the Eastern Province to Riyadh, largely to supply the domestic power sector. The Government foresees that the share of gas in the country's total primary energy mix will rise from 42% in 1999 to 65% by 2005.

Qatar ranks third in the world, after Russia and Iran, for total gas resources. The country's proven gas reserves are estimated at 14.4 tcm. This represents an increase of 30% compared with the beginning of 2000, due to the upward revision of recoverable natural gas reserves of the North Field. Undiscovered resources are estimated at 1.2 tcm. This figure appears to be very low and will certainly be revised upward. Qatar produced 30.8 bcm in 2000, of which 14.5 bcm was processed and exported as LNG from two plants at Ras Laffan (QatarGas, with three trains and total capacity of 6 Mt/year; and RasGas, with two trains and capacity of 6.4 Mt/year).

The *UAE* have 6 tcm of proven gas reserves. Discovery of the Khuff reservoirs and other non-associated gas structures have boosted gas reserves in recent years. Undiscovered gas resources for the UAE are estimated by USGS at 1.3 tcm. Production, which totalled 39.1 bcm in 2000, is expected to rise strongly in the coming years. Development projects currently underway include:

- three onshore reservoirs under the Bab oil field (OGD 2) and the installation of gas and condensate recovery and recycling facilities at the onshore Asab field;
- the installation of facilities for the production of 11 bcm/year of natural gas and 40,000 to 55,000 b/d of condensate from three reservoirs under the Bab field;
- the further development of the Khuff gas reservoirs under the offshore Abu al Bukhoosh and Umm Shaif oil fields; output will supply local industrial and power-generation projects, will be re-injected to sustain oil production and will be exported to Dubai.

Iraq is the least explored of the major oil and gas producers. According to Iraqi sources, undiscovered resources (free and associated) are estimated at more than 9 tcm, which is considerably higher than USGS estimates. Iraq's gas reserves at the beginning of 2001 totalled just over 3 tcm, of which just over 2 tcm (71%) was associated gas. Production has recovered gradually since the Gulf War, reaching almost 5.1 bcm in 2000, most of which was marketed to the power sector and industry. The rest was re-injected or flared. Prospects for output for the foreseeable future will depend on domestic demand, although a project to export gas to Turkey has been proposed.

Oman has limited reserves, 605 bcm according to Cedigaz, but produces significant amounts of gas mainly for export as LNG. Output at the country's only liquefaction plant, with two trains and a total capacity of 6.6 Mt/year, began in 2000. Expansion of capacity and the development of new plants will probably require a big increase in reserves.

Given the region's vast reserves and relatively low costs of production, the Middle East has the potential to expand inter-regional trade and increase its role as an exporter of natural gas to Asia and Europe. Plans to establish an integrated regional gas grid within the Gulf Co-operation Council[50] have been under consideration for more than a decade. The project would entail a gas pipeline linking Qatar to the UAE, Oman, Kuwait, Saudi Arabia and Bahrain. A regional gas grid is of particular interest to Dubai, which has seen its natural gas consumption rise sharply and which now faces a supply shortfall. In the near term, imports from Abu Dhabi via a 112-kilometre pipeline to Jebel Ali commissioned in 2001 will fill the gap. The most advanced proposal is the ambitious Dolphin Gas

50. Bahrain, Kuwait, Oman, Qatar, Saudi Arabia and the United Arab Emirates.

Project, entailing the construction of an 800-kilometre-long sub-sea pipeline with an initial capacity of 30 bcm/year. The $8 to $10 billion project would deliver gas from Qatar's North Field to al Taweelah in Abu Dhabi, where it would connect up with the Abu Dhabi-Jebel Ali line in Dubai and on to Oman. Ultimately the line could extend to Pakistan and India. Construction of the first phase is scheduled to begin in mid-2001 with completion expected in late 2002 or early 2003, but it is unlikely that the timetable will be kept. Major issues to be resolved include border disputes, financing and pricing.

Iran is seeking to develop export projects based on its massive gas reserves, initially focusing on the South Pars field. Iran has agreed to export gas by pipeline to Turkey. Exports were supposed to have started in 2000 at a rate of 3 bcm/year, rising to 10 bcm/year by 2005, but insufficient gas availability from South Pars and delays in commissioning the pipeline, due partly to financing problems, have delayed the project. Exports of gas from the Kangan and Khangiran fields and possibly re-exports of imported Turkmen gas are now expected to begin in the second half of 2001. LNG exports are also planned. A 50:50 joint venture agreement has been signed by the Oil Industries and Construction Company (an affiliate of the National Iranian Oil Company) and BG International to develop a two-train plant with a capacity of up to 7 Mt/year. Production could begin in 2006, probably supplying India. A longer-term export option, is to build a large-capacity pipeline to Pakistan/India. The near-term viability of this project is doubtful, given diplomatic tensions between India and Pakistan (which would hamper onward sales to the big Indian market), and the need to re-inject gas for secondary oil recovery in Iran.

Elsewhere, a number of new LNG projects or expansions are planned. *Qatar* could increase its exports of LNG through the expansion of existing plants and the development of new greenfield projects, supported by the massive reserves of the North Field. Two more liquefaction trains with a combined capacity of 7.6 Mt/year are planned at the RasGas plant to supply 3.5 Mt to Edison in Italy from 2005, 1.5 Mt to Spain's Gas Natural and possibly up to 2 Mt/year to Petronet's terminal in India are planned. A new single-train LNG expansion project is also under consideration in *Oman*, with a planned start-up in 2004. This would supply a terminal planned by Shell in India, but this project will depend on securing adequate reserves. A two-train project has also been proposed in *Yemen*.

Figure 3.26: **Inter-regional and Export Gas-Supply Projects in the Middle East**

Table 3.18: **Middle East LNG Projects**

Country	**Project**	**Current capacity** (Mt/year)	**Expansion** (Mt/year)	**New Project** (Mt)	**Status**
Abu Dhabi	Adgas	5.5 (3 trains)	-	-	-
Oman	Oman LNG	6.6 (2 trains)	3.3 (1 train)	-	Subject to negotiations with Shell and to finding adequate reserves; possible go-ahead in 2001 and project start-up in 2004
Qatar	QatarGas	6.8 (3 trains)	1.5	-	Expansion through debottlenecking; possible go-ahead in 2001
	RasGas	6.6 (2 trains)	9.4 (2 trains)	-	2-phase expansion, to supply Edison, Italy and possibly Petronet, India
Yemen	Yemen LNG	-	-	5.3 (2 trains)	No sales agreement. Earliest start-up in 2005
Iran	OICC/BG International	-	-	7 (2 trains)	Production could begin in 2006; sales agreement with BG import terminal in Gujarat under negotiation

Source: IEA database.

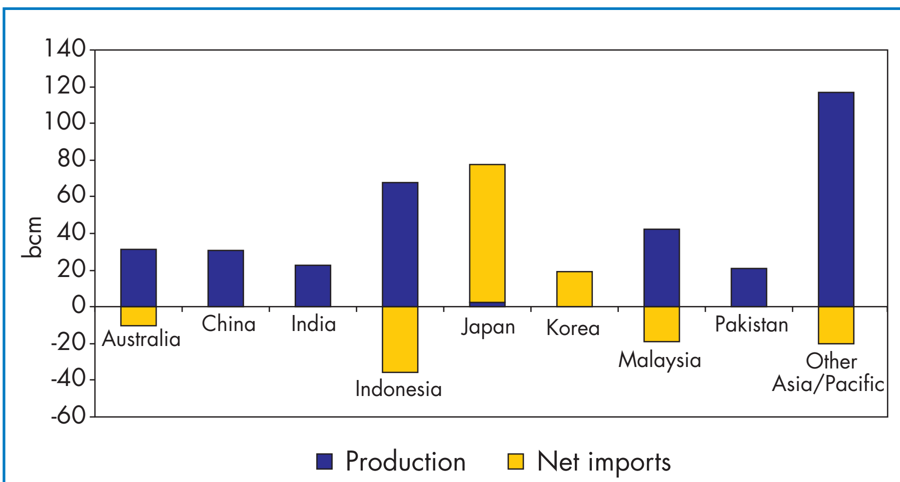
Asia/Pacific

Market Overview

The Asia/Pacific region[51] is very diverse in terms of economic prosperity and maturity, domestic gas resources and patterns of gas consumption. After the Middle East, the Asia/Pacific region has been the fastest-growing market for natural gas over the last decade, with demand rising at an average annual rate of 6.5% per year. Demand is currently concentrated in Japan, Australia and Korea, but is *growing* fastest in the least developed countries. Outside of Australia, demand is dominated by power generation, and petrochemical and fertiliser manufacturing.

Natural gas resources and production are focused on a small number of countries. Australia, Malaysia, Brunei and Indonesia are gas exporters, mainly to Japan and Korea. But a major part of the region's gas needs are met by imports from outside the region, mainly from the Middle East. The main importers are Japan, Korea and Chinese Taipei. With the exception of a small volume of gas exported by pipeline from Malaysia and Indonesia to Singapore and from Myanmar to Thailand, all trade in gas is in the form of LNG.[52]

Figure 3.27: **Asia/Pacific Natural Gas Supply, 2000**



Note: Net exports are negative.
Source: IEA (2001).

51. This Section groups the countries of the OECD Pacific region, China, East Asia and South Asia.
52. Asia/Pacific countries accounted for 74% of total LNG imports in 2000.

Demand and trade – both within and with countries outside the region – are expected to grow steadily in the medium term, driven by rapid economic growth and by environmental pressures to switch from coal to gas. Almost half the projected 5% per year projected increase in demand from 1997 to 2020 is accounted for by China and India, and much of the rest by other East Asian countries, including Indonesia, Korea and Thailand.

Resources and Production Prospects

The Asian/Pacific region contains 15 tcm of gas, equivalent to 9% of global gas reserves. The region includes four major LNG producers: Indonesia, Malaysia, Australia and Brunei.

Table 3.19: **Asia/Pacific Proven Gas Reserves and Undiscovered Resources** (bcm)

	Proven reserves (at 1 January 2001)	**Undiscovered gas resources** (mean, at 1 January 1996)
Indonesia	3,790	3,048
Australia	3,530	3,097
Malaysia	2,420	1,420
China	1,515	2,428
Others	3,696	4,542
Total	**14,951**	**14,535**

Sources: Reserves – Cedigaz (2001); Resources – USGS (2000).

Australia has large and expanding gas reserves and further large resource potential. Cedigaz estimates Australia's proven gas reserves at 3.5 tcm. The latest official figures put gas reserves at 2.8 tcm, of which only about 800 bcm have been classified as proven and probable. The rest have not been declared commercially viable at current prices. Major gas discoveries were made in 1999 and 2000, including discoveries by the West Australia Petroleum consortium in the Gorgon area offshore northwestern Australia. The discovery enhanced the resource base in the nearby fields of Gorgon, West Tryal Rocks, Spar, Chrysaor and Dionysos. These structures may contain more than 490 bcm of proven and probable reserves.

To date, Australian production has centred on the onshore Coopers/Eromanga Basin, which supplies markets in Queensland, New South Wales, the Capital Territory and South Australia, and the Gippsland Basin offshore Victoria. The Amadeus Basin supplies gas to Northern Australia. The Carnarvon (Northwest Shelf) and Perth Basins serve Western Australia. Production is expected to shift from the Coopers/Eromanga and Gippsland Basins, where reserves are declining, to the Carnarvon Basin and to the Timor Sea in Northern Australia. The latter may support LNG exports as well as serve local demand, possibly feeding in to a planned pipeline system that could extend to Queensland. Demand in Queensland, however, is unlikely to be sufficient to support such a project, at least until 2010, in view of the planned construction of a 5.5 bcm/year pipeline from Papua New Guinea to Queensland, to be commissioned by 2005 at the earliest. Northwest Shelf production will depend on LNG exports, which will in turn depend on demand from and competition in the rest of the Asia/Pacific region. The green light for a 7 Mt/year Northwest Shelf expansion underpinned by contracts with Japanese buyers was given in March 2001, with first gas expected in 2004. A Gorgon LNG plant is a possibility, although probably not until after 2010.

Indonesian gas reserves are also large. The Government estimates reserves at 4.5 tcm (somewhat higher than the Cedigaz estimates shown in Table 3.19), of which 2.6 tcm are proven and 1.9 tcm are probable. This is three times as much as the country's oil reserves and equivalent to 50 years of supply at current production rates. Over 71% of gas reserves are located offshore, with the largest reserves situated off Natuna Island (33%), East Kalimantan (30%), Irian Jaya (15%), Aceh (7%) and South Sumatra (6%). Although the Government is keen to increase supply to the domestic market, production is largely export-driven. Indonesia is currently the largest LNG producer in the world, with two plants at Arun[53] (6 trains and 12.3 Mt/year of capacity based on Aceh) and Bontang (8 trains and 21.6 Mt/year based on East Kalimantan). Exports amounted to 35.7 bcm in 2000 – equivalent to 53% of total production.

Increased LNG exports will depend on capacity expansions at Bontang and new greenfield projects. Arun production is declining. The priority for the Indonesian Government is an LNG project based on the recently discovered Tangguh field, which has proven reserves of at least 420 bcm. Indonesia's proximity to East Asia/Pacific markets gives it a cost

53. Production at Arun was virtually halted in early 2001 when the main fields supplying the plant were shut down due to civil unrest.

advantage over potential new Australian and Middle Eastern projects. But export plans may be threatened by political instability surrounding independence movements in several provinces. The development of the large Natuna field remains uncertain due to the cost of processing the gas, which has very high CO_2 content.

Malaysia's gas potential is very large. Of the 2.4 tcm of remaining gas reserves, 40% are on peninsular Malaysia, 51% on Sarawak and 9% in Sabah. Shell recently discovered major new deepwater-gas reserves (Kamusu East 1, Block G). Production on the Peninsula supplies the local market and Singapore. Output is expected to rise in response to growing power-generation demand, but exports will be limited by Singapore's efforts to diversify its imports. Malaysia is already a major LNG exporter of Sarawak gas from its Bintulu plant, with a total of 6 trains and capacity of 15.9 Mt/year. Exports in 2000 were 18.7 bcm, or 44% of total output. Two additional trains with a combined capacity of 6.8 Mt/year are under construction with deliveries planned to begin in 2004.

China's resource potential is uncertain, but resources are, in any case, much greater than current estimates of reserves might suggest. According to official figures, there were 171 discovered gas fields in China at the beginning of 2000. Proven geological reserves were 2.3 tcm, and proven recoverable reserves were 1.5 tcm, while remaining recoverable reserves were 1 tcm. Conventional resources of 50.6 tcm were proven, but only 13.3 tcm are reckoned to be recoverable. The relatively sparsely populated and under-developed Western and Central areas contain roughly 59% of total resources. Within these two areas, three basins – Tarim, Sichuan and Ordos – hold 90% of local and 52% of national resources. The Sichuan basin accounted for most of the country's gas output of 30.5 bcm in 2000, but output from Tarim, Ordos, Qinghai and offshore fields is growing. The Government recently announced a 200-bcm gas discovery in the northern part of the Tarim basin in the Xinjiang province.

Connecting the producing fields in the west and centre of China to the main potential markets in the east will require the construction of long-distance transmission lines and expansion of distribution networks. At present, China's transmission infrastructure is fragmented and distribution networks under-developed. In 2000, the Government approved the construction of a 4,200-kilometre pipeline, the West-East Transportation Project, to ship gas from the Tarim Basin to Shanghai. But the fate of this 12 bcm/year project, which is expected to cost around $5.4 billion, will depend on foreign investment. The Government aims to complete the first

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section of the line between the Changqing field and Shanghai by 2003, with the remaining section from Tarim Basin to be completed in 2004. The state-owned Chinese National Petroleum Corporation estimates the delivered cost of the gas in Shanghai at around $4.50/Mbtu. This estimate raises doubts about whether the gas could compete with other fuels – especially if oil prices were to fall.[54] Further doubts concern the firmness of reserve estimates and the speed of demand growth, which would both affect the economic viability of the project. Other gas-supply options, including piped imports from Russia and LNG from Asia or the Middle East, appear to be cheaper options.

Brunei's gas reserves are estimated at 366 bcm. The Southwest Ampa field holds more than half of Brunei's total gas reserves and it accounted for 60% of the country's total production of 10.1 bcm in 2000. More than 80% of the gas produced is exported as LNG. Brunei is the world's fourth-largest producer of LNG and currently has contracts to supply 6.2 Mt/year to Japan and Korea. There are no plans to expand LNG capacity, but this may change if new discoveries are made.

Intra-regional Trade and Imports

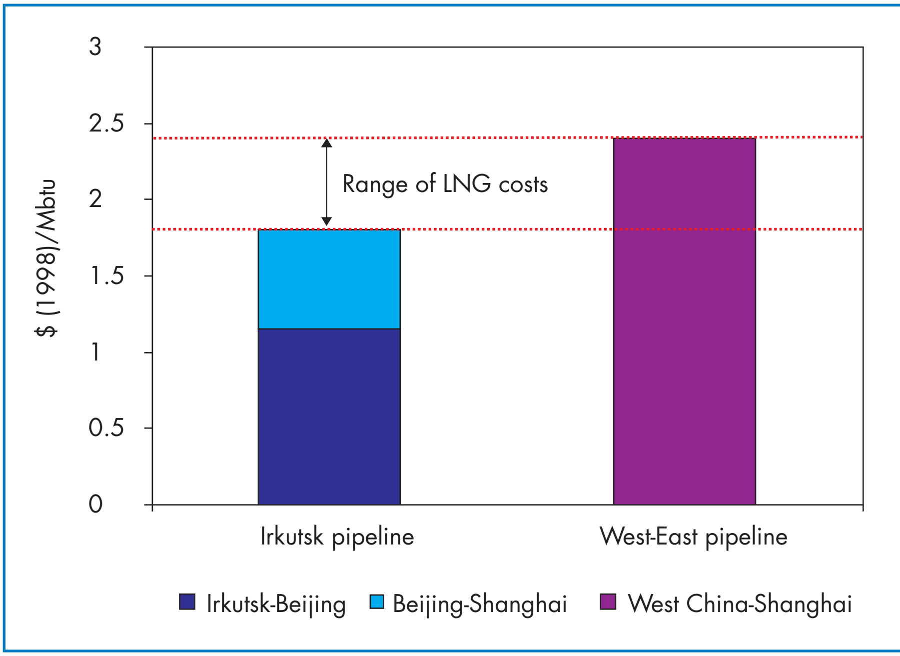
China

Chinese gas consumption is projected to grow at an average 7.5% per year from 1997 to 2020. These projections suggest that China's indigenous reserves will not be sufficient to meet domestic demand and that additional imported supplies will be required despite an expected increase in indigenous production.

The most likely near- to medium-term sources of imports are Russian gas by pipeline from the Kovykta field near Irkutsk or from Sahka in Eastern Siberia and LNG imports from Asian or Middle Eastern producers. Of the pipeline options, Irkutsk is the most likely to proceed although its timing will depend on whether the West-East pipeline goes ahead, whether the Irkutsk pipeline is extended to Korea and Japan, whether adequate reserves are proven and on whether financing can be found. There are two possible routes for the line – a direct route traversing Mongolia and a more circuitous one that avoids Mongolia. The preferred option will depend on negotiations with Mongolia over transit fees. The initial investment in a 56-inch pipeline would be around $7 billion. Asia Pacific Energy Research Centre estimates that unit transportation costs

54. Gas Matters (October 2000*), China's Leaders Throw Their Weight Behind East-West Gas Pipeline.*

Figure 3.29: **Indicative Pipeline and LNG Transportation Costs to Shanghai, China**



Notes: Estimates are for APERC's larger-demand scenario and assume no re-export of gas. Costs do not include the cost of the gas itself, other than that used as compressor fuels and in liquefaction and regasification.
Source: APERC (2000).

would be around $1.10/Mbtu to Beijing and $1.60/Mbtu to Shanghai, assuming high initial throughput and no re-exports.[55] This implies that Irkutsk gas could probably be delivered to Shanghai for around $2.50, including the cost of the gas. This is certainly less than the cost of transporting gas from Western China or from other, more distant foreign sources such as Turkmenistan or Kazahkstan, and it is cheaper than LNG for most distances. But political considerations related to the development objectives for Western China and wellhead prices may favour the West-East pipeline and LNG imports. Moreover, other estimates suggest much higher costs for Irkutsk gas.[56]

The Sahka pipeline option appears to be more costly and therefore unlikely to be adopted in the near term. Technical difficulties due to permafrost conditions in Northeastern Siberia as well as the greater

55. APERC (2000).
56. For example, FACTS, in discussions with the IEA, have suggested a delivered gas cost of around $3/Mbtu to Beijing, without re-exports.

distances involved and the more dispersed nature of the reserves, mean that production and transportation costs are likely to be much higher than for Irkutsk. In the longer term – probably beyond 2015 – pipeline imports from further afield may become viable, as the cheaper, nearest-to-market sources are used up.

Plans to import LNG are moving ahead with the Chinese Government's decision in early 2001 to approve the construction of the country's first receiving terminal in Guandong, South of Hong Kong, with a capacity of 3 Mt/year. Other terminal sites have also been proposed.

India

The potential demand for gas in India is enormous, given the projected rate of industrial expansion and the current low level of gas use. Indigenous production is unlikely to grow fast enough to meet demand. Gas imports into India are projected to reach 46 bcm in 2020. But this projection is subject to a number of uncertainties, including project development costs, financing arrangements and political considerations.

The three main gas import options for India are:

- *LNG:* More than a dozen terminals have been proposed, but to date only one is under construction: Enron's 5 Mt/year terminal at Dabhol to supply its already-built power station from the end of 2001. Work on the terminal was recently halted due to a dispute over payment for power supplies. A project by Petronet LNG (a consortium of four domestic oil companies and Gaz de France) to build a second terminal at Dahej, Gujarat is well advanced, with deliveries set to begin in 2004. Shell is also pressing ahead with a 5 Mt/year terminal at Hazira due to be commissioned in 2004, with supply to come from Oman. Delivered prices being negotiated for new projects are reportedly around $3/Mbtu excluding regasification costs.[57] This corresponds to an ex-terminal price of under $3.50/Mbtu. Although LNG is the most expensive of the import options, it is expected to account for the lion's share of gas imports over the next two decades. The amount of imports during that period is very uncertain, however, due to problems with financing, pricing and risk of non-payment.
- *Pipeline from Bangladesh:* This is probably the lowest cost import option in the near term, but, for political reasons, the Bangladeshi Government has not yet authorised exports.

57. FACTS (2000).

- *Pipeline from Iran, Qatar or Central Asia via Pakistan:* This is probably the lowest-cost long-term import project, but it is hindered by tensions between India and Pakistan, risks associated with transit through Afghanistan and doubts about the availability for export of the vast reserves of Iranian gas from South Pars. An offshore pipeline bypassing Pakistan has been proposed, but the cost would be much higher. It is unclear whether gas piped from the Middle East or Central Asia will become economically and politically viable before 2015.

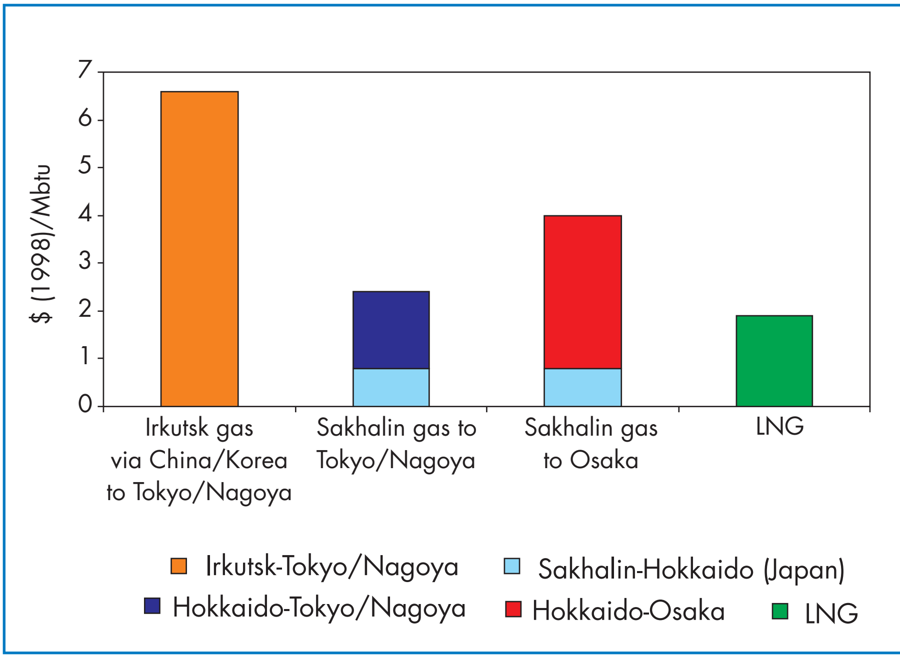
Japan

The principal options for Japan to meet any future increase in natural gas demand include increased imports of LNG from Asia, the Middle East or Alaska or Russian gas piped from Sakhalin or Irkutsk via China and Korea. Imports, which account for 96% of natural gas use in Japan, are now entirely in the form of LNG, coming from Indonesia, Malaysia, Australia, Brunei, the UAE, Qatar, the United States (Alaska) and Oman. Imports reached 72.5 bcm in 2000.

The most likely sources of additional LNG supplies in the next decade are from existing major suppliers and possibly Russia (Sakhalin 1 and 2). Japan is already committed to lifting more LNG from Malaysia (MLNG III Tiga), starting in 2003, and from Australia (Northwest Shelf expansion), starting in 2004. This will partly make up for the expiry of existing contracts. New export projects under consideration in Australia (including Gorgon and North Australia), Qatar (North Field), Indonesia (Tangguh and Natuna), Oman (Qalhat) and Alaska (North Slope) could provide additional gas. Increased LNG purchases will probably be conditional on more competitive pricing formulae and more flexible contracts, with shorter terms. A growing proportion of any new demand is likely to be met by spot purchases. Bringing LNG from Sakhalin will partly depend on prospects for a pipeline.

The viability of each of the two main pipeline options – Sakhalin and Irkutsk – will depend on how rapidly the need for additional imports emerges, the cost compared to LNG projects and financing considerations. APERC's transportation-cost estimates suggest that neither Sakhalin nor Irkutsk is likely to be economic before 2010. Figure 3.30 compares the results of APERC's indicative cost analysis of these pipeline projects compared to LNG transportation costs. The economics of the Irkutsk and Sakhalin projects are particularly sensitive to the cost of onshore and offshore pipelines in Japan.[58] The very large capital costs involved, as noted above, will undoubtedly hinder financing, especially for the Irkutsk project.

Figure 3.30: **Indicative Pipeline and LNG Transportation Costs to Japan**



Notes: Estimates are for APERC's larger demand scenarios for Japan and Korea. Pipeline costs include taxes on profits in countries traversed, but not transit fees. The Chinese option assumes an onshore trunkline to Osaka and Tokyo. The Sakhalin option assumes an offshore line. The LNG cost estimate is derived from generic cost estimates and the average distance of the current supply portfolio. Costs do not include the cost of the gas itself, other than that used as compressor fuels and in liquefaction/regasification.
Source: APERC (2000).

Korea

Virtually all of Korea's incremental gas needs will have to be imported for the foreseeable future. Depending on the pace of demand growth, Korean buyers will probably need to contract for new supplies at some

58. Pipeline-laying costs in Japan are very high due to difficulties in gaining rights-of-way in densely-populated areas and obligatory safety measures to deal with the risk of earthquakes. For this reason, it would normally be more economic to site trunklines offshore in shallow water.

point after 2005. The flexibility in Korea's existing long-term contracts with Indonesia, Malaysia and Brunei, and spot purchases, could postpone the need to sign new large-volume contracts. The options for new greenfield LNG projects include Tangguh in Indonesia, the Australian Northwest Shelf Expansion, Gorgon and North Australia, Sakhalin-2 and the Middle East plants. Beyond 2010, the Irkutsk pipeline project could become economically viable depending on Chinese and Japanese purchases, Chinese transit fees and the comparative cost of the project versus the cost of LNG. APERC estimates the transportation cost of Irkutsk gas at around \$1.50/Mbtu with throughput to Japan and about \$2.10/Mbtu without re-exports, compared to about \$2/Mbtu for LNG.

Southeast Asia

Southeast Asian countries are co-ordinating a regional efforts to expand intra-regional trade through the Trans-ASEAN Gas Pipeline (TAGP) project. This inter-governmental initiative aims to create pipeline links between regional gas reserves and major demand centres in Thailand, Malaysia, Singapore, Indonesia and, ultimately, the Philippines. The project looks to establish the regional grid in a progressive way through the construction of discrete cross-border pipelines over the next ten to twenty years. The TAGP is currently proceeding through an evolutionary process of developing national pipeline systems and cross-border interconnections between neighbouring national systems. Myanmar and Thailand are already connected, as are Malaysia, Singapore and Indonesia. ASEAN expects that these two regional grids will be connected by 2005. Pipeline routing will be determined by the location and size of reserves, market growth and financing considerations. It is expected that power generation will account for much of the projected increase in demand. The success of these plans will depend on the harmonisation of regulatory policies across the region, pricing and market growth.

Latin America[59]

Market Overview

Latin America has emerged in recent years as one of the fastest-growing markets for natural gas, underpinned by abundant resources, growing energy demand and economic integration. Primary use of natural

59. This Section draws on information contained in a forthcoming IEA publication, *Natural Gas Market Reform and Integration in South America.*

gas in Latin America (including Mexico) totalled 140 bcm in 2000, accounting for approximately a quarter of the region's primary energy mix. Consumption is heavily concentrated in Argentina (36.8 bcm), Mexico (39 bcm) and Venezuela (27.6 bcm). Trinidad (9.9 bcm), Brazil (8.7 bcm), Colombia (7.2 bcm) and Chile (7.0 bcm) account for most of the rest. These figures include gas that is re-injected, flared or lost in gas processing, which accounts for around 40% of total production. Marketed production was approximately 94 bcm in 2000, an 8% increase over 1999. Over the last decade, marketed natural gas production in the region has increased at an annual rate of more than 5%. Trinidad and Tobago is currently the only LNG exporter in the region. It has been supplying around 3 Mt/year (3.6 bcm) to Spain and the United States since 1999.

Regional trade blocs such as Mercosur (Argentina, Brazil, Uruguay and Paraguay, with Chile and Bolivia as associated members) and the Andean Pact (Bolivia, Peru, Ecuador, Colombia and Venezuela) have facilitated cross-border trade and boosted demand for gas. Inter-regional trade amounted to some 6.6 bcm in 2000: 4.7 bcm from Argentina to Chile and 1.9 bcm from Bolivia to Brazil. Democratisation, economic liberalisation and the deregulation and privatisation of the energy sector in several countries have helped attract foreign and domestic capital and technology for a number of large gas-pipeline projects. Only a few years ago, such projects would have seemed impossible.[60]

Reserves/resources

Proven gas reserves in Latin America amount to 7.74 tcm, more than half of them in Venezuela (Table 3.20). They represent 5% of the world's total reserves. Major discoveries made recently in Bolivia, Trinidad and Tobago, Argentina and Brazil demonstrate the area's gas potential. USGS estimates undiscovered resources at just over 15 tcm (mean) for the region.

Venezuela's proven gas reserves and undiscovered resources are the largest in the region. Most proven reserves are associated gas (90%). Up to now, Venezuela's exploration work has primarily targeted oil. But there are attractive areas of non-associated gas, which were offered to private investors under licensing agreements in the spring of 2001.

Argentina's proven gas reserves amounted to 743 bcm at the beginning of 2001. Neuquen is the most prolific basin, with 53% of gas reserves. In *Bolivia*, the export of gas to Brazil and the liberalisation of the gas sector has led to a surge in gas exploration. As a result, proven gas reserves increased

60. For example, Petrobras holds a stake in the Bolivia-Brazil pipeline.

Table 3.20: **Latin American Proven Gas Reserves and Undiscovered Resources** (bcm)

	Proven reserves (at 1 January 2001)	**Undiscovered gas resources (mean, at 1 January 1996)**
Argentina	743	1,038
Bolivia	855	708
Brazil	242	5,502
Mexico	835	1,394
Trinidad	705	900
Venezuela	4,163	2,865
Others	671	2,775
Total	**8,214**	**15,182**

Sources: Reserves – Cedigaz (2001); Resources – USGS (2000).

six-fold in 1999 and 2000 to 855 bcm at the beginning of 2001. Major gas accumulations were discovered in San Antonio, San Alberto and Itau X-1. *Mexico* has been poorly explored. The national oil and gas company, Pemex, has initiated a programme to increase natural gas production from non-associated fields in order to boost gas production without simultaneously increasing the production of crude oil. *Trinidad and Tobago* gas reserves have increased dramatically, to 705 bcm, following major gas discoveries since 1996. According to Petrobras, proven gas reserves in *Brazil* doubled in 2000 to 229 bcm. Undiscovered resources are particularly high at 5.5 tcm (mean).

Prospects for Production and Trade

Flows between Latin American producing countries and high-growth consuming countries are expected to increase rapidly in the next few years, as several new pipelines come on line. Natural gas supply and inter-regional connections are expected to develop quickest in the Southern Cone, a region encompassing southern Brazil, Argentina, Chile, Bolivia, Paraguay and Uruguay. The development of gas interconnections among the Andean countries, Peru, Ecuador and Colombia will probably progress more slowly.

Box 3.9: **Southern Cone Pipeline Projects**

In 1999, gas began to flow through a key section of the nascent integrated gas grid in the Southern Cone. The 3,000-kilometre 32-inch Bolivia-to-Brazil pipeline cost some $2 billion and has a capacity of 11 bcm/year. Inaugurated in July 1999, it is currently supplying 2.9 bcm/year of Bolivian gas to southern Brazil (Sao Paulo and Porto Alegre). Supply is expected to increase to at least 5.8 bcm/year in 2006. Recent gas discoveries indicate that Bolivia can sustain even higher exports for many years. Several other pipelines are under construction or have been announced, which will ultimately supply the giant Brazilian market.

On the western side of the continent, two more pipelines have recently been completed, boosting the supply of Argentinean gas to Chilean industries. In the north, the Gasoducto Atacama, a $750-million, 940-kilometre project will be able to move 3.1 bcm/year of gas from Argentina's Noreste basin to Mejillones, Chile. In southern Chile, the 640-kilometre $320-million Gasoducto del Pacifico was recently completed, linking the Argentinean Neuquen basin to several Chilean towns south of Santiago. The other two pipelines linking Argentina to Chile are GasAndes (La Mora-Santiago) and Magallanes in the far south.

While the large reserves in the north are too far away to supply pipeline gas economically to Southern Cone markets, they offer great potential for LNG projects. The Trinidad and Tobago plant is being expanded with the addition of two 3.3 Mt/year liquefaction trains scheduled to come into operation in 2002 and 2003. Venezuela plans to follow Trinidad and Tobago's example and export LNG to the United States, Europe and northeastern Brazil. Brazil has plans for two LNG-importing terminals, although only one will probably go ahead initially. Bolivia is considering LNG exports to Mexico and the United States with a liquefaction plant based in Chile or Peru. Mexico could become a net exporter of gas by pipeline to the United States, depending on domestic demand trends and the rate of investment in exploration and development, which in turn depends critically on prices and regulatory reforms, including the possible opening up of the sector to foreign investment.

Figure 3.31: Existing and Planned Natural Gas Pipelines in Latin America

While the potential for market development is very large, the investments needed to bring projects to reality are enormous. The prospects for gas supply and exports will depend crucially on the establishment of a clear and stable fiscal and regulatory environment to win investor confidence. This is especially true for Brazil, where the regulatory regime for electricity remains very uncertain and is hindering the development of gas-fired power projects.

CHAPTER 4
GLOBAL COAL SUPPLY OUTLOOK

Summary

Coal will remain the largest energy source for power generation, and internationally traded coal will grow in importance

- Coal demand is projected to rise by 1.7% a year on average in the *WEO 2000*. The equivalent of 117 billion tonnes of coal will be consumed in the period to 2020. The bulk of the growth, some 85%, will be stimulated by demand for coal in power generation. In the OECD, virtually all the increase in coal demand will stem from power generation. With mounting electricity demand, China, India and other developing countries in Asia will contribute the strongest impetus to the increase in world coal demand.
- International seaborne coal trade will play a larger role in supplying world coal needs, as demand increases in regions without broad indigenous high quality coal resources and in regions where coal production is declining. Seaborne coal trade will grow by 50% in the period to 2020 and will continue to play an important role in world coal supply. Steam coal for power generation will increase its share of the international market, driven mainly by strong growth in the key regional markets, Asia-Pacific and Europe-Atlantic.

Coal reserves are vast and widely dispersed...

- Coal production will expand in regions which develop, or maintain, competitive-coal industries. Production will increase in China, the United States, India, Australia, South Africa, Indonesia, Canada, Colombia and Venezuela. Production will continue to decline in OECD Europe. The Asia-Pacific market will be supplied mainly by Australia, Indonesia and China because of geographic proximity. South Africa, the US, Colombia and Venezuela will be the primary suppliers to the Europe-Atlantic market. South Africa's geographic location enables it to supply Europe, Asia and the Americas; and its role in transmitting price signals between the

regional markets will remain an important component of the international coal market price setting mechanism.

- World reserves of coal are enormous and, compared with oil and natural gas, widely dispersed. According to most recent estimates, economically recoverable coal reserves are close to one trillion tonnes. The world's proven reserve base represents about 200 years of production at current rates. Almost half the world's reserves are located in OECD countries, and concerns over coal supply security are less important than for oil and gas.
- The quality and geological characteristics of coal deposits are more important to the economics of production than the actual size of a country's reserves. Quality varies from one region to another. Australia, Canada and the United States all have high-quality coking coal. Australia, China, Colombia, India, Indonesia, Russia, South Africa and the United States have very large reserves of steam coal.
- Proven coal reserves have increased by over 50% in the past 22 years. The correlation of strong growth of proven coal reserves with robust production growth suggests that additions to proven coal reserves will continue to occur in those regions with strong, competitive coal industries.

...and supply costs are expected to remain stable

- As in the past, implementation of advanced mining technology will continue to improve efficiency and to lower the cost of coal extraction and preparation. Health and safety performance will improve further as more automation and larger-scale mines proliferate. If investments are made in advanced mining and combustion technology, they will continue to mitigate the costs of meeting increasingly stringent environmental regulations.
- Transport often represents a large proportion of the total cost of delivering coal to end users—as much as 50% of the steam-coal import cost into Europe and Japan. Policies and measures need to focus on expansion of transport and handling facilities, but there is no physical barrier to continued expansion. Transport availability and costs are unlikely to constrain future coal supply.

Price-setting mechanisms will evolve further

- The international coal market plays a crucial role in price setting. Because domestic coal industry performance is increasingly assessed against the standards of the international market, prices set by buyers and sellers in the international market will affect domestic energy production and consumption decisions. Prices in the two key regional markets, Europe-Atlantic and Asia-Pacific, move in close relationship. They link the major commercial-coal producers with energy markets in the major consuming regions—Europe and Japan. The importance of the international coal market in setting domestic and international energy prices will grow, as competitive coal industries evolve in other important producing regions.

- The role of long-term supply contracts with annual price negotiations has declined in importance. For steam coal, a spot market has evolved that reflects the balance of supply and demand in the market. While there is not yet an international coal exchange, the recent development of more spot-market volume and of e-business suggest that coal markets will grow more liquid. Reliance on a more dynamic pricing mechanism will ensure efficiency in world coal markets.

The key uncertainty affecting future coal use is the impact of environmental policies on demand

- The coal-supply and price outlook hinges on the effect of new environmental and climate change polices on demand prospects. Investors may show a reluctance to commit the large resources necessary to ensure a sufficient coal supply in the current landscape, where long-term demand is placed at risk by the possible introduction of environmental and climate change policies.
- The rate at which clean-coal technologies are adopted and the scope at which they are put into place will both be crucial for future coal use.

Sustained investment is crucial in many countries

- Sustained investment in both production and transportation infrastructure is vital to the coal supply outlook. This is especially true in China and India, where coal remains an important component of energy supply and future economic development.
- Government resources are used to subsidise the coal industry in some countries, but subsidies have been reduced or removed over the past decade in many of them. Security of energy supply has been advanced as a rationale for maintaining uncompetitive coal production in some OECD countries, while most non-OECD countries with subsidised coal production are engaged in reform and restructuring of their coal industry to improve performance and investment prospects. Reforms which direct financial resources

towards the creation of commercially competitive coal industries are an important component of maintaining stable coal supply and prices.

Overview of Coal Market Trends

Demand

The *World Energy Outlook 2000* projects global coal demand to grow by some 1.7% per year between 1997 and 2020.[1] Demand declined in 1997, 1998 and 1999. Much of this contraction is attributable to China, where government policy has increasingly favoured other fuels. Preliminary data for 2000 show a further decline of coal demand in China. But world coal demand recovered in 2000, with a 1% increase over 1999.

World coal demand will increase from 2255 Mtoe in 1997 to 3350 Mtoe by 2020. Based on these projections and on the physical tonne to Mtoe conversion ratio in 1997, cumulative world demand in the period to 2020 will reach nearly 120 billion tonnes. With some 985 billion tonnes of proven coal reserves, global demand will exhaust less than 12% of the world's existing inventory by 2020. Figure 4.1 summarises the *WEO's* projections of coal demand by region and for China and India.

The bulk of projected growth will be in the power generation sector, and, to a lesser extent, in iron and steel and other heavy industries. Coal is likely to maintain its position as the world's largest source of electricity generation through to 2020. Its share in this sector has remained almost unchanged for about three decades and is projected to stay roughly the same until 2020. Coal demand in the residential, commercial and light industrial sectors is expected to continue its decline.

Based on *WEO 2000* demand projections, steam coal demand is expected to grow by 2.6% annually. In OECD countries, virtually all the increase in demand for coal will stem from power generation. The switch from coal to gas in industrial applications and in household heating will continue. China and India, with ample coal reserves and rising electricity demand, will contribute more than two-thirds to the increase in world demand over the projection period. Rising demand for coal-fired electricity generation in other Asian countries will rely on indigenous brown coal and imported hard coal.

1. The base year for *WEO 2000* projections is 1997, the last year for which IEA data was available at the time of publication. The projections of coal demand in *WEO 2000* were in tonnes of oil equivalent (toe). In this chapter, coal demand and supply figures have been converted to metric tonnes, which is the unit most commonly used by the coal industry.

Figure 4.1: **World Coal Demand by Region**

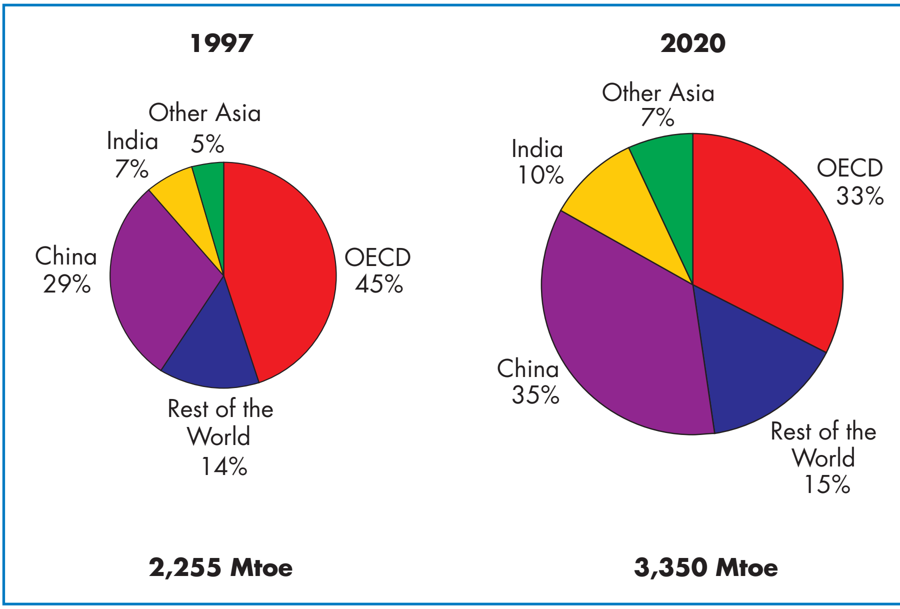


Table 4.1: **World Coal Demand**

	1997		**2020**		**1997-2020***
	Mtoe	**% Share for power generation**	**Mtoe**	**% Share for power generation**	
OECD	1,013	79	1,091	86	**0.3**
North America	541	92	647	94	0.8
Europe	342	66	301	78	-0.6
Pacific	130	57	144	68	0.4
Non-OECD	**1,242**	**47**	**2,260**	**60**	**2.6**
Transition Economies	203	48	284	55	1.5
Africa	87	57	143	57	2.2
China	662	40	1,192	55	2.6
India	153	67	366	76	3.5
Other Asia	103	46	231	71	3.6
Latin America	28	35	56	53	3.1
Middle East	7	83	18	89	4.4
World	2,255	**61**	3,350	**69**	**1.7**

* Average annual growth rate, in percent.
Source: IEA (2000).

Demand for coking coal is projected to grow at a much slower pace, as a result of changes in steel production technologies which favour alternatives to coking coal. Projected growth for coking coal is 0.8% annually from 1997 to 2020.

Coal Production and Trade Implications

Because coal is a bulk commodity, it is expensive to transport; the world coal industry is dominated by local production for local use. Although world coal production rose steadily from the late 1950s to 1990, growth rates varied among regions and countries. Since 1978, hard and brown coal production has plummeted in OECD Europe; but these production declines have been offset by strong growth in Australia, China, India, Indonesia, South Africa, Latin America and the United States.

Hard coal has a higher energy value than brown coal and is more likely to be transported longer distances; the vast majority of internationally traded coal is hard coal, which is used for heat and power generation and for coke-making. Lignite and brown coal have higher ash and moisture contents and lower energy values and are thus more likely to be burned near their point of mining for heat and power generation.

Since 1990, there have been two periods of contraction in world coal production: from 1990 to 1992, when output of hard and brown coal/lignite in the FSU and Central and Eastern Europe declined sharply; and from 1997 to 1999, when Chinese hard coal production fell significantly. Other factors that contributed to the decline of coal production in the late 1990s were low prices, which dampened producers' incentive to increase production, and the ongoing effort to reduce subsidised production in several European countries. The past two years have seen a resurgence in coal demand and prices, which is likely to arrest production declines in most commercially competitive coal producing countries in the near term.

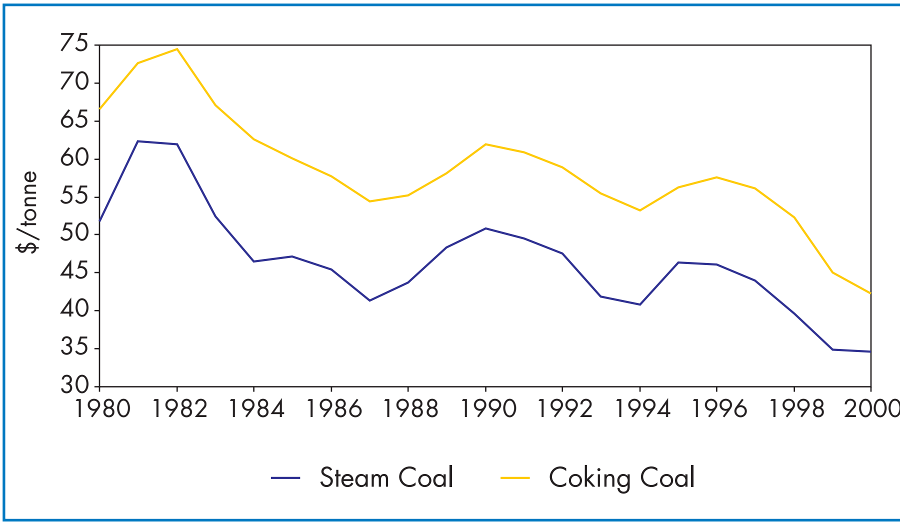
With coal reserves widespread geographically, coal demand can usually be met on a regional basis. Internationally traded coal accounts for only some 12% of total world demand. Seaborne trade was about 478 million tonnes in 1999, of which steam coal accounted for 65%. Seaborne trade expanded by 10.4% in 2000, to 527 million tonnes. The share of steam coal increased to 66%. Steam coal will continue to gain market share in world coal trade over the next two decades, stimulated mainly by strong electricity demand growth in major importing markets.

The international coal market is well-established and has a large number of buyers and sellers who move hard coal, principally by sea. Trade has risen steadily since the 1970s despite occasional declines in global demand and production. Trade growth has occurred mainly in two major markets, Europe-Atlantic comprised of European countries and Middle Eastern countries bordering the Mediterranean Sea; and Asia-Pacific, comprised of Japan and developing market economies in Asia. The primary impetus for trade growth is that these regions lack large domestic coal resources that are competitive and that are of the quality necessary for heat and electricity generation and for coke-making in integrated steel production. Smaller but important markets have also evolved in South Asia, Latin America and North America for the same reason.

World coal prices have declined steadily in both real and nominal terms over the last 20 years as productivity of both coal extraction and coal transport has improved. The nominal price of steam coal imported by OECD countries declined from over \$50 per tonne in 1980 to less than \$35 per tonne in 2000. Similarly, the nominal price of coking coal imported by OECD countries declined from over \$74 tonne in 1982 to less than \$43 per tonne in 2000. Although both steam and coking coal import prices strengthened in late 2000, and have remained strong in 2001, they have not returned to the highs experienced in 1995 and 1996. Although many industry experts agree that prices need to be higher to stimulate more supply in the international coal sector, few expect them to be sustained at the 2001 level in the long term, as new suppliers are already responding to price signals by bringing more product to the market.

The decline in the price of internationally traded coal has caused a realignment of world coal production. OECD Europe's restructuring of its coal industry, and the resulting decline in domestic production, was stimulated by the wide difference in the price of domestically-produced coal and internationally traded coal. Similarly, in Japan, as subsidies have been reduced, domestic output has fallen to less than 2% of total coal demand. Since coal reserves are abundant and widely dispersed geographically, importing countries have a choice of suppliers, which ensures diversity of supply, competitive prices, reliability and quality. The expansion of international coal trade will continue as lower cost, higher quality coal moves into new power generation markets and displaces more expensive and lower quality indigenous coal in the Europe-Atlantic and Asia-Pacific markets.

Figure 4.2: **OECD Import Coal Prices**



Source: IEA, *Energy Prices and Taxes, Quarterly Statistics* (fourth Quarter 2000).

Key Factors Affecting Coal Supply Prospects

Coal Reserves and Production

Definitions

Estimating coal reserves is based on a consideration of geological, mining and economic criteria. The amount of coal in place, and in some cases the amount of mineable coal, is defined by national resource measurement criteria, which vary among countries.[2] Some generally recognised definitions follow:

- **Resources** refer to the amount of coal that may be present in a deposit or coalfield. This definition does not take into account the economic feasibility of mining the coal or the fact that resources may not be recoverable using current technology.
- **Reserves** constitute those resources that are recoverable using current technology. The category may be divided into "proven" (or

2. During the 1990s, there was considerable discussion on the adoption of internationally recognised standards for reporting reserves. To date, however, there is still no international standard.

measured) reserves, and "probable" (or indicated) reserves, based on exploration results and the degree of confidence in those results. "Probable" reserves indicate a lower degree of confidence than "proven" reserves.

- **Proven reserves** can be recovered economically under current market conditions. This definition takes into account current mining technology and the economics of recovery, including mining and transport costs, government royalties and coal prices. Proven reserves decrease when prices are too low for the coal to be recovered economically, and increase when prices make the coal economically recoverable.

Coal Reserve Estimates

In its most recent *Survey of Energy Resources*[3], the World Energy Council (WEC) estimates current proven coal reserves at 984.5 billion tonnes. This includes anthracite, bituminous and sub-bituminous coal and lignite.[4] The WEC statistics for proven reserves by country and by region are consistent with IEA Coal Research's assessment published in *Major Coalfields of the World*.

The classification of coal by quality varies from country to country, and it is not possible to estimate proven reserves by coal type.[5] If total 1999 proven reserves are divided by total 2000 coal production, however, the world reserve base represents more than 200 years of production at current levels. As Table 4.2 indicates, OECD North America and the transition economies each accounted for 26% of the world's proven coal reserves in 1999. About 12% of proven reserves were in China, and 11% in OECD Europe. Some 75% of proven coal reserves are concentrated in these four regions.

Coal quality and the geological characteristics of coal deposits have as much importance as the actual size of a country's reserves. Quality varies widely from one region to another. With steam coal, calorific value, ash, sulphur and moisture content are the most important quality characteristics. Steel-makers require high-quality coal which has low moisture, ash, sulphur and phosphorus content, and other more technical characteristics related to coke-making needs. While steam coal reserves are

3. World Energy Council (2001).
4. See Box 4.1 for coal classification.
5. An overview of the national classification systems is provided in an Appendix to *Major Coalfields of the World*. (IEA Coal Research, 2000).

more widespread, mining costs and quality characteristics affect the marketability of production. Coking coal reserves are more limited. The United States, Australia and Canada are endowed with substantial reserves of premium coals that can be used to manufacture coke.

Table 4.2: **Proven Recoverable Reserves at End-1999** (billion tonnes)

	Bituminous and sub-bituminous	***Brown/ Lignite***	***Total***
OECD Europe	52.1	52.4	104.5
OECD North America	222.6	35.4	258
OECD Pacific	45.5	38	83.5
OECD	**320.2**	**125.8**	**446**
Transition economies	212.6	38.1	250.7
of which: Russia	146.6	10.5	157
China	95.9	18.6	114.5
East Asia	3.3	4.5	7.8
South Asia	84.7	2	86.7
of which: India	82.4	2	84.4
Latin America	21.6	0.1	21.8
of which: Colombia	6.3	0.4	6.7
Venezuela	0.5	0	0.5
Brazil	11.9	0	11.9
Africa	55.4	0	55.4
Middle East	1.7	0	1.7
World	**795.4**	**189.1**	**984.5**

Source: World Energy Council (2001).

Box 4.1: Coal Classification

Classification of coal based on quality

Coking coal is coal with a quality that allows the production of coke suitable to support a blast-furnace charge. Other coals are classified according to their calorific value. Bituminous coal and anthracite have the highest calorific value, greater than 23,865 kJ per kg on an ash-free but moist basis. Sub-bituminous coal has calorific value of between 23,865 kJ/kg and 17,435 kJ per kg. Lignite/brown coal has the lowest calorific value of the three categories, less than 17,435 kJ per kg.

Use of coal to produce energy

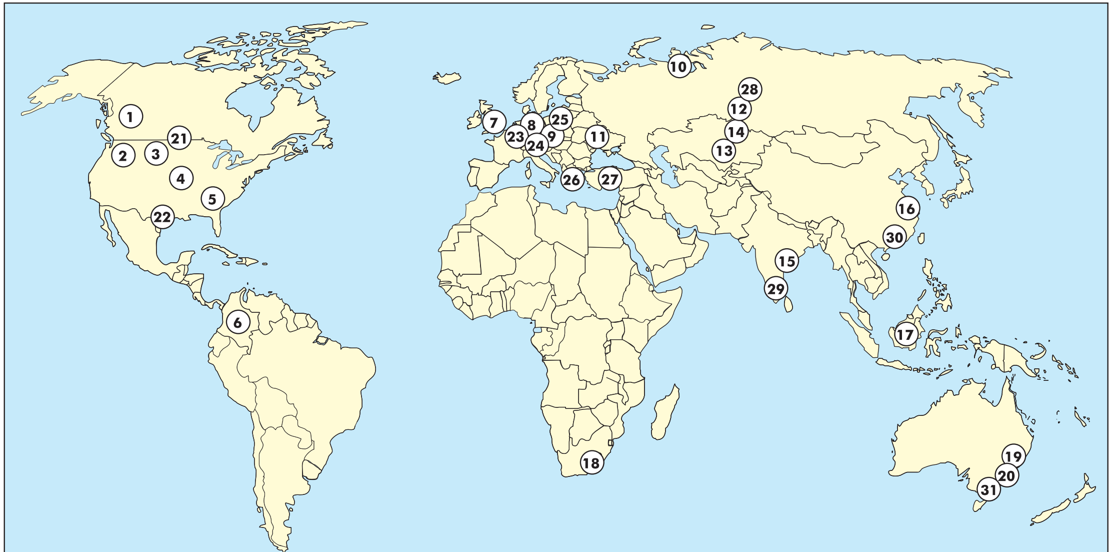
The IEA defines total coal as the sum of hard coal and brown coal after conversion to a common energy unit (tonne of coal equivalent). This conversion is done by multiplying the calorific value of the coal by the total volume of hard and brown coal used. Hard coal is the sum of coking coal and steam coal. As a primary input, cooking coal is used to produce coke in a coke oven, and steam coal is used to produce heat and electricity.

Historical Changes in Reserve Estimates

In 1978, WEC estimated proven coal reserves to be 636.4 billion tonnes. Thus, world proven coal reserves have increased by 54%, or 348 billion tonnes in the past 22 years, even though cumulative production from 1978 to 2000 amounted to an estimated 101 billion tonnes. Since proven coal reserves are defined as the resources that can be recovered economically, the distribution of proven coal reserves has changed over the past three decades as a result of changes in relative costs among countries. Along with the overall increase of proven coal reserves, there has been relatively spectacular growth in the proven reserve base in some regions.

From 1978 to 1999, proven coal reserves in the transition economies—the former Soviet Union (FSU) and Central and Eastern Europe—more than doubled, from 122.7 billion tonnes to 250.7 billion tonnes. Most of the new proven reserves are in the sub-bituminous category. Bituminous coal reserves increased only modestly and lignite reserves were nearly the same in 1999 as in 1978.

Figure 4.3: **Location of World's Major Hard Coal and Lignite Basins**



Hard Coal

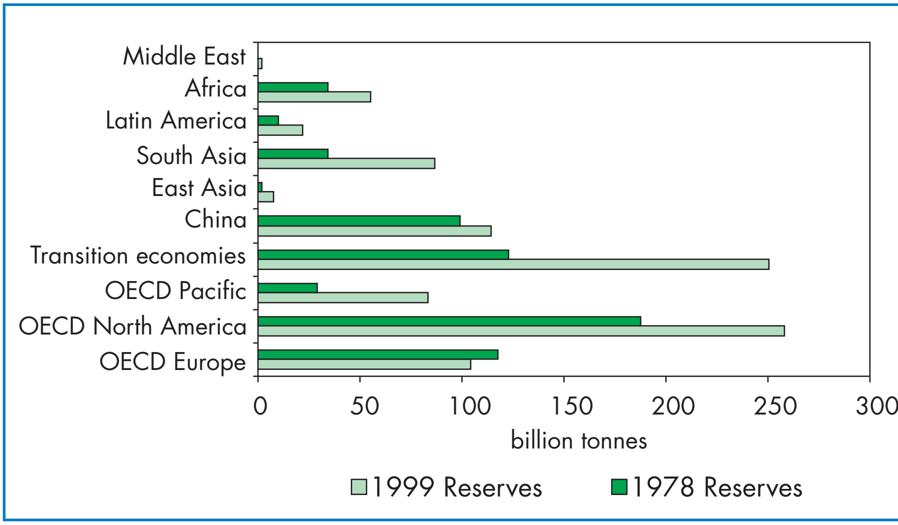
1	Western Canada	11	Donetsk, Ukraine/Russia
2	Western USA	12	Kusnetsk, Russia
3	Powder River basin, USA	13	Karaganda, Kazakhstan
4	Illinois basin, USA	14	Ekisbastuz, Kazakhstan
5	Appalachia, USA	15	Jharia/Raniganj, India
6	Guajira, Colombia	16	Eastern China
7	East Pennine, UK	17	Kalimantan, Indonesia
8	Rurh, Germany	18	Karoo, South Africa
9	Upper Silesia, Poland/Czech Republic	19	Bowen basin, Australia
10	Pechora, Russia	20	Sydney basin, Australia

Lignite

21	Great Plains, USA/Canada
22	Gulf Coast, USA
23	Rhineland, Germany
24	Bohemia, Czech Republic
25	Poland
26	Greece
27	Turkey
28	Kansk-Achinsk, Russia
29	Neyveli, India
30	China
31	Victoria, Australia

Source: IEA Coal Research (2000).

Figure 4.4: **Distribution of Proven Coal Reserves, 1978 vs. 1999**



Source: World Energy Council (2001).

Proven reserves in South Asia, located mostly in India, also more than doubled, rising from 34.2 billion tonnes in 1978 to 86.7 billion tonnes in 1999. Nearly all of the increase was of hard coal quality. Proven reserves in the OECD Pacific region nearly tripled in size. Increases were primarily hard coal and brown coal added in Australia. More modest increases of proven reserves were experienced in OECD North America, Africa, Latin America, East Asia and China. Proven coal reserves declined in OECD Europe by 11% from 1978 to 1999, or some 13 billion tonnes.

Over the past two decades, the global distribution of proven coal reserves has shifted towards the transition economies and South Asia and away from OECD Europe. The share of world coal reserves in the transition economies increased from 19% in 1978 to 25% in 1999, while the share of South Asia rose from 5% to 9%. The OECD Pacific region also experienced an increase in share—from 5% to 9%. The relative share of proven coal reserves in OECD North America and in China declined moderately over the period. In East Asia, Latin America, the Middle East and Africa, the relative share of proven coal reserves remained about the same.

With the exception of the transition economies, which experienced a decline in production related to the effects of political and economic restructuring, increased proven coal reserves have been correlated with increased production. Proven reserves increased in Africa, Latin America, South Asia, China, OECD Pacific and OECD North America—all regions which experienced coal production growth. The relationship between proven coal reserve growth and production growth is related to the fact that, as coal production, consumption and transportation infrastructure is expanded, resources in close proximity to exploited reserves also become economically viable and enter the proven reserve classification. Strong production growth is generally a precursor to strong growth in proven coal reserves, ensuring that future coal demand can be supplied as current production expands.

OECD Europe's share of world reserves dropped from 19% in 1978 to 11% in 1999. The contraction of the proven reserves estimate for OECD Europe was paralleled by a decline in the coal industry. The contraction shows both the depletion of existing reserves, and a shift from economically viable to non-viable for reserves located in deposits too deep or too thin to mine within the technological and market parameters of 1999.

Historical Coal Production[6]

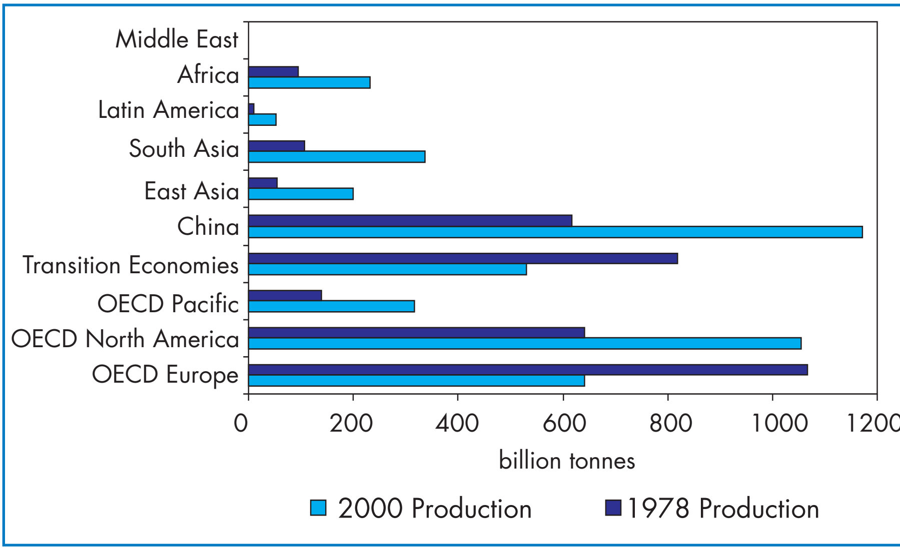
The countries that make up today's OECD Europe produced 1.1 billion tonnes of hard and brown coal in 1978, when they were the largest producing region in the world. West and East Germany combined produced over 468 million tonnes of hard and brown coal. Poland, the Czech Republic (formerly part of Czechoslovakia), and the UK each produced well over 100 million tonnes of hard and brown coal annually in the late 1970s.

By 2000, hard and brown coal production in OECD Europe countries had declined to 640 million tonnes. Production also fell in the transition economies, declining from 819 million tonnes in 1978 to an estimated 531 million tonnes in 2000.

The largest production increase over the past 22 years occurred in China, where annual coal production jumped by 553 million tonnes. OECD North America experienced an increase of 413 million tonnes. Although the increase was not so pronounced in volume terms in other regions, the percentage increases over the past 22 years are quite significant — Latin America (368%), East Asia (266%), South Asia (215%), Africa (148%) and OECD Pacific (128%).

6. This section discusses historical coal production patterns from 1978 so that production trends can be compared with both the 1978 and the most recent WEC *Survey of Energy Resources*.

Figure 4.5: **Total Coal Production, 1978 vs. 2000**



Source: IEA (2001a).

Total world coal production increased at a relatively brisk pace from 1978 to 1989. But the dissolution of the Soviet Union and the replacement of planned economics in Eastern Europe by market-oriented regimes set off a sharp decline in total coal production in these economies, resulting in a steady decline in world coal production from 1990 to 1993. Global production recovered slowly from 1994 to 1997, but declined in the next three years. Although 2000 saw a modest resurgence of coal demand (up 1% on 1999), world coal production, at 4.5 billion tonnes, was down by some 10.2 million tonnes, or 0.2% from 1999. Recent declines in world coal production can be attributed to the following factors:

- China has been rationalising hard-coal production by closing small unsafe and uncompetitive mines, while at the same time reducing coal consumption in some urban industrial, household and commercial markets.
- Four OECD Europe countries—France, Germany, Poland and Spain—have ongoing programmes to reduce heavily subsidised coal production.
- Low world and domestic coal prices dampened incentives to increase coal production in some of the major producing and exporting countries. For example, production in the US has

declined for two years, and Canadian production has declined for three years. Production declined in India, Colombia and Venezuela in 1999. Production increases were small in Australia and South Africa in 1999 and in Indonesia in 2000. Although the weakness in each country can be partially attributed to unique social or political conditions, the production declines were also the result of domestic and international supply cost and price pressures.

Table 4.3: **World Coal Production, 2000** (million tonnes)

Region or Country	**Hard Coal**	**Brown Coal**
OECD Europe	205	437
OECD North America	936	119
OECD Pacific	249	68
OECD	**1,389**	**623**
Transition economies	324	207
of which: Russia	169	86
China	1,171	0
East Asia	157	42
South Asia	313	23
of which: India	309	23
Latin America	52	0
of which: Brazil	6	0
Colombia	37	0
Venezuela	9	0
Africa	231	0
Middle East	1	0
World	**3,638**	**896**

Source: IEA (2001a).

In 2000, the ten largest producing countries were responsible for 84% of production (Table 4.4). Supply price and demand conditions in international markets are usually reflected to some extent in the domestic market conditions which producers face. This tendency, however, is strongest in South Africa and Australia, where exports take 30% and 60% of total production volume, respectively. In the United States, Russia, and Poland, where exports take from 5% to 15% of volume, domestic market conditions are a stronger influence. In countries where the coal industry is subject to strong government controls, like China, India, North Korea, Russia and Ukraine, government policy, domestic energy requirements and the need for hard currency tend to dictate production decisions and the volume of exports.

Four of the ten largest exporters, Indonesia, Colombia, Canada and Kazakhstan, are not among the ten largest producers. In Indonesia, Colombia and Canada, international market forces strongly affect hard-coal production decisions. In Kazakhstan, market conditions in the other transition economies, particularly Russia, strongly affect hard-coal production decisions.

Table 4.4: **Ten Largest Producers and their Exports in 2000**
(million tonnes)

	2000* Production	% of World Total	Production Rank	2000* Exports	% of Total	Export Rank
China	1,171	25.8	1	55	9.3	3
United States	976	21.5	2	53.1	9	5
India	332	7.3	3	0.4	0.1	20
Australia	306	6.7	4	177.2	30.0	1
Russia	255	5.6	5	34.4	5.8	6
South Africa	225	5	6	66.8	11.3	2
Germany	205	4.5	7	0.2	0	22
Poland	161	3.5	8	23.7	4	10
North Korea	91	2	9	0.4	0.1	21
Ukraine	82	1.8	10	1.9	0.3	15
Subtotal, Ten Largest	**3,804**	**83.9**		**413.1**	**69.9**	**n.a.**
Other Producers (55 countries)	**730**	**16.1**		**179.1**	**30.1**	**n.a.**
World Total (65 countries)	**4,534**	**100.0**		**591.2**	**100.0**	**n.a.**

* Estimate.
Source: IEA (2001a).

Coal Reserves and Production Outlook

Although world coal resources are widely distributed, proven coal reserve expansion will occur in those regions with strong coal production growth—especially regions that have world class competitive coal industries. This means that regions that have experienced strong proven reserve growth over the past three decades will continue to see growth.

In the Asia-Pacific region, Australia and Indonesia will host strong reserves expansion. In the Americas, strong expansion will occur in areas like the US, Canada, Colombia and Venezuela. In Europe, proven reserves in the transition economies will expand, while reserves in OECD Europe will continue to decline. Future proven coal reserve expansion in China and India is uncertain. The further development of dynamic and competitive coal industries, which can attract investment and thrive in both domestic and international markets, will be the most important factor in these countries.

Similar to reserves, coal production can be expected to expand in the regions which host competitive coal industries. In this context, production will increase in South Africa, Australia, China, Indonesia and North and South America. Production will continue to decline in OECD Europe.

In OECD North America, the replacement of depleted reserves will coincide with coal production expansion to meet new thermal-coal demand for power generation. The maintenance of the region's position in world coking markets will encourage capital investment in coal production and handling and in further resource exploration. Extension of the transport infrastructure and application of advanced mining technology are expected to maintain the growth of the region's coal reserves and production capability over the next two decades.

In the OECD Pacific, Australia will remain a major coal exporter, and growth of its base of proven coal reserves will be supported by moderate domestic demand and strong export growth. The wages of coal miners are relatively high in Australia, but they are offset by investment in large-scale mines and advanced mining technology which ensures high productivity. The result is a world-class commercial coal industry capable of sustaining high steam and coking coal export volumes at competitive costs. Because of its cost efficiency and volume capability, Australia will remain the cost-setting coal supplier in the Asia-Pacific market. Australia will also continue to play the role of cost-setting supplier in the Europe-Atlantic market, when US coal producers cannot. Strong production growth of steam and coking coal in the Hunter Valley and Bowen Basin will stimulate continued expansion of the proven reserve base in the future.

The coal-reserve base in OECD Europe declined 11% between 1978 and 1999. A larger decline is likely in the future. Projected consumption over the next twenty years will equal 25% to 30% of the existing reserve base. Production will continue to decline rapidly. This underscores the importance of a competitive and reliable international coal sector, since coal demand will be increasingly met with imports.

South African production will be maintained well above the level needed to support domestic demand. Expansion of coal production and transport infrastructure will focus on two areas: the use of capital intensive, large-scale, more efficient technology to expand existing proven reserve areas; and expansion of transportation and production infrastructure into less developed coalfields like the Waterberg. A stable business environment is critical so that coal producers remain confident of the return on their investments.

Colombia and Venezuela are the most important coal producers in Latin America. To retain their share of the global coal export market, they will need to maintain production well in excess of the level needed to meet domestic demand. Currently, they produce 90% to 95% more hard coal than is necessary to meet domestic demand, and ship the extra production widely in the international steam-coal market. Coal transportation infrastructure in Latin America, however, is inadequate. The development of new production capacity and the opening of new reserves are highly contingent on solving this problem. Further, the stabilisation of social and business conditions is needed so that coal producers remain confident of a long term return on their investments.

Some 42 billion tonnes of coal demand is projected for China through 2020. By fulfilling this demand primarily with domestic production, China will deplete about 37% of current proven reserves. Since China added only 15.6 billion tonnes to its proven coal reserves from 1978 to 2000, despite a large production increase, further introduction of advanced technology, as well as expansion of the coal transport infrastructure, is necessary to increase the proven reserve base. By opening some of its coal producing areas to the international commercial coal market, China has stimulated development of a world-class coal industry in several regions of the country.

About 12 billion tonnes is projected for coal demand in India through 2020. Although India has become a significant hard-coal importer in the last decade, meeting projected demand entirely from domestic production would deplete only some 14% of India's current proven reserve base. The Indian reserve base has sufficient economic resources to support proven reserve and coal production growth, well into the future. But India must raise the necessary capital and develop management skills to improve productivity and to introduce economies of scale to its coal mining sector. The coal and electric power sectors need to install coal-washing and flue-gas cleaning facilities to meet environmental and coal combustion standards. India's viability as a coal producer is more contingent on meeting physical and human capital investment needs, than on the adequacy of its proven coal reserve base.

In the transition economies, proven coal reserves in traditional producing areas are expected to decline. But expansion of coal production and transportation infrastructure will ensure expansion of the proven reserve base in areas which are economically competitive and which possess marketable coal qualities. Proven brown coal and lignite reserves will also be likely to expand as power generation technology improves, and as new and retrofitted environmental equipment is installed in the power generation sector.

Supply Costs

There have been substantial advances in coal mining technology in the last 30 years, with vast improvements, in those countries where the technology has been adopted, in health, safety, environmental performance, labour productivity and extraction costs. Advances in coal mining, however, are not evenly distributed. The more developed countries have achieved better performance, productivity and cost levels than have countries which are heavily reliant on manual labour in small-scale operations. In countries where many coal reserves are approaching depletion, and in those where government subsidies have been used to maintain uneconomic production, growth in labour productivity has lagged.

Coal supply costs consist of coal extraction and preparation costs and the costs of transporting coal to the end user. Coal extraction and preparation costs generally include the costs of reserve acquisition and control, exploration and engineering, coal mining and crushing, washing and other treatment, and land reclamation. Transportation costs include loading, haulage for truck, rail, barge or other means, handling when transferring from one mode of transport to another, and storage. Handling and storage costs can be incurred at any point along the transportation chain where coal is discharged from one transport mode and reloaded onto another, or at the endpoints of the transportation chain in the producer's or the consumer's stock areas.

Coal supply costs vary, depending primarily on the location and geology of the coal reserves, coal quality and the extraction technology used. Costs also depend, to a lesser extent, on labour productivity, power and fuel costs, capital costs, end-user location, government policies on royalties and severance costs, health and safety regulations and environmental regulations.[7]

Coal-Extraction Costs

Coal-extraction costs depend on the geology of the coal reserve, which governs the type of mining technology that can be used. Coal mines fall into two categories—underground and opencast. World wide, two-thirds of hard coal is extracted from underground mines, though the proportion is much lower in some important producing countries, such as Australia, Canada, Colombia, Indonesia and the US. Opencast mining has expanded rapidly in the past twenty years, as more advanced excavation and materials-handling systems have been developed. A primary advantage of opencast mining is its scale. Some opencast mines are multi-million tonne-per-year operations—often covering tens of thousands of hectares with coal extraction taking place as deep as 100 metres.

Most modern underground coal extraction methods are a version of either "room-and-pillar" or "longwall" mining. Although room-and-pillar mining has lower capital costs and causes less subsidence at the surface, its disadvantage is that coal recovery seldom exceeds 60%. While initial capital investment and ongoing capital costs in longwall extraction can be five or six times higher, labour productivity is often four to five times higher, and 80% to 90% of the coal seam is recovered.[8]

Room-and-pillar

Room-and-pillar operations are descended directly from the oldest method of underground coal mining. Its principal advantage is safety, in that a solid coal pillar maintains the security of the roof. Other advantages include application to a wide range of seam thickness, small-scale, easy "start-and-stop" characteristics as market conditions may dictate, and flexibility for selective extraction from the coal seam. In its most basic form, room-and-pillar extraction can be accomplished with manual labour using

7. The location and quality of the coal and the extraction costs can have effects on other coal-supply costs. For example, labour productivity tends to be higher with opencast mining technology, but opencast mining depends upon the depth of the coal seams; coal can be shipped unwashed, but this depends upon the *in situ* quality of the coal, end-user needs and transportation distance.
8. IEA Coal Research (2001).

picks for coal cutting and shovels for loading, and manual haulage from the coal face to the surface. Mechanised room-and-pillar technology consists of two basic approaches:

- Conventional mining, where coal is "undercut" by a cutting machine, drilled and blasted with explosives, and then loaded into shuttle cars for transport to the surface.
- Continuous mining, where coal is cut with a drum-type mining machine with direct loading into shuttle cars or continuous haulage systems for rapid transport of mined coal.
- Several advances have been made in continuous mining in the past decade, and improvements are expected to go on enhancing performance and safety, while reducing the unit cost of production. The highest rates of labour productivity achieved in continuous operations have been in Australia and the US. Although the distribution of productivity depends heavily on geological and operational factors, productivity of up to 10,000 tonnes per miner per year have been achieved on a regular basis.[9]

Longwall

Longwall mining developed in Europe as the need to produce coal at very great depths required leaving large coal pillars and substantially lowered recovery rates in room-and-pillar mines. An advanced longwall mine employs a large "shear" or coal-cutting mechanism which moves back and forth on a panel of the coal-face that can be 300 or more metres wide. Hydraulic supporting devices are used above and behind the shear to hold up the roof.

Longwall mines are extremely capital intensive, not only because of the cost of the equipment but also because of the long lead-time needed for planning and panel development. In order to provide access to the longwall panel, "gate roads" need to be built along the sides. Longwall panels can reach nearly 7,000 metres in length.

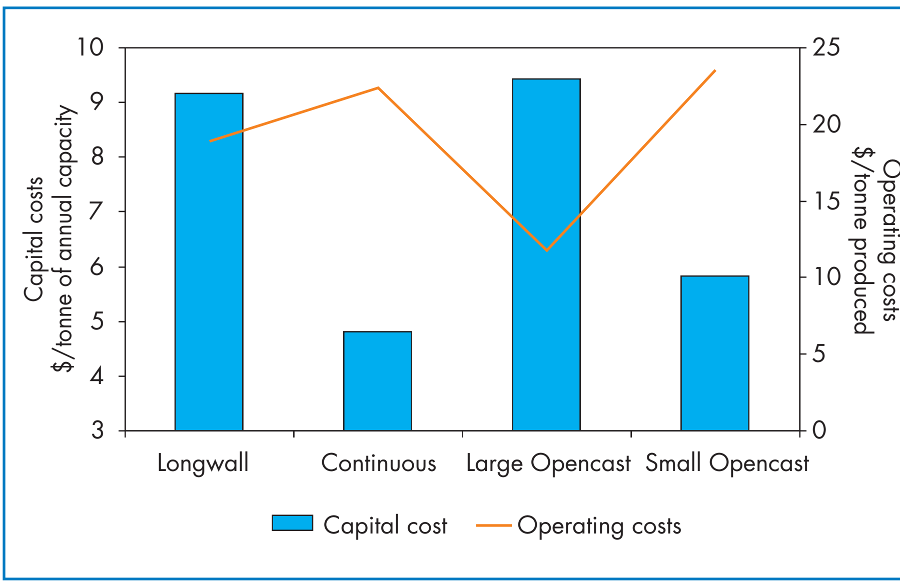
The highest rates of labour productivity achieved in longwall operations have been in Australia and the US. Companies only choose longwall mining where they control a large reserve for a long period of time, and have a market capable of absorbing the production. In longwall mining, productivity of up to 40,000 tonnes per miner per year have been achieved on a regular basis.[10]

9. IEA Coal Research (1996).
10. Energy Information Administration (1995).

Opencast Mining

Extraction of coal by open-pit excavation requires removal of soil and rock from above the coal. Soil-and-rock removal is often the main activity and the most expensive in development of an open-pit mine. Opencast mines range from small-scale operations removing coal from exposed outcroppings to huge surface mines using several draglines and shovels and a fleet of transport trucks. Opencast operations have a greater surface footprint than deep mines. Subsequent reclamation and renewal of the mine site constitutes a large part of the overall costs of operation. Productivity in area surface mines has a wide range, with small-scale operations working in thin seams and in thick overburden and producing 5,000 to 10,000 tonnes per miner per year. Large-scale operations with multiple thick seams in relatively thin overburden can produce 35,000 to 50,000 tonnes per miner per year.[11]

Figure 4.6: **Estimated Coal Mine Operating and Capital Costs, 2000**



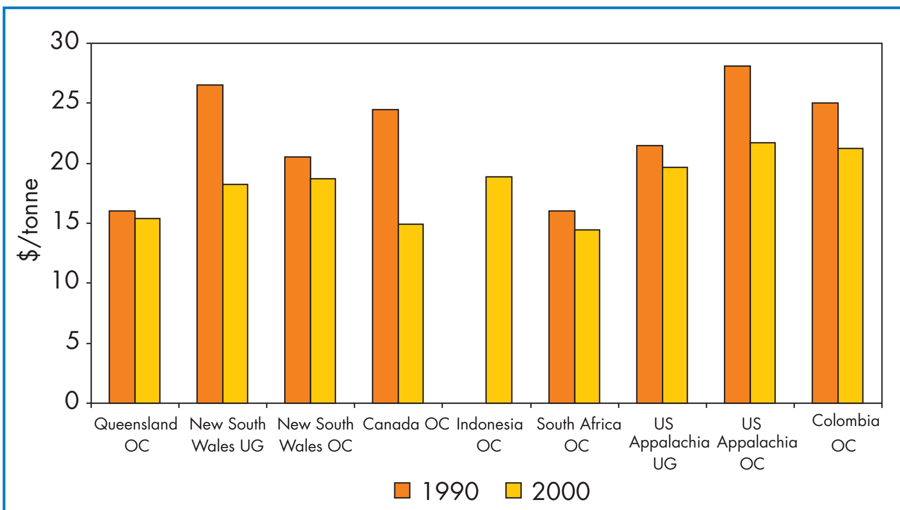
Source: IEA analysis.

11. US Department of Commerce (1986) and updated with IEA analysis.

The range and scale of coal-extraction technologies permit coal producers to adapt mining to many different geological conditions, labour conditions, environmental regulations, capital resources and domestic or international market conditions. While current coal-mine operations favour large-scale longwall or opencast development, unique conditions at the mine site and the producer's resources ultimately dictate the technology choice. Figure 4.6 illustrates the trade-offs that producers face in their selection of technologies.

Figure 4.7 illustrates the difference in coal costs among major international coal-trading nations. Since 1990, IEA Coal Research has estimated these costs annually. They are based on country-specific reserves, environmental standards, labour practices and tax and royalty regimes. The estimates reflect both coal-extraction and coal-preparation costs. The years 1990 and 2000 are used to illustrate not only the cost differentials among countries, but also the degree to which overall costs have changed over the past decade.

Figure 4.7: **Selected Steam Coal Mine Operating Costs, 1990 vs. 2000**



Notes: OC = opencast; UG = underground.
Source: IEA analysis.

Coal-Preparation Costs

Coal preparation ranges from simple breaking, crushing and screening to ensure adequate flow and uniform size to intense washing and drying to meet stringent ash, moisture and sulphur standards. Most coal is partially crushed at or near the mine site to enable its easy conveyance to the processing plant. At its most primitive, coal preparation can consist of passing raw, broken coal slowly over a series of "picking tables" where rocks and other impurities are removed by hand. This approach is still used in countries with cheap labour and with capital constraints.

Coal washing is the most prevalent type of preparation. Two factors contribute to coal-washing costs:

- *The "recovery rate" or the rate at which clean coal is extracted from raw coal.* One important measure in the sale of coal is weight, and the amount of saleable product is affected by the recovery rate. The removal of ash, pyrite and other impurities reduces the weight, especially in coals with high inherent ash content. In cases where coal must meet very stringent ash and sulphur standards—most hard coking coals—recovery rates range from below 50% to 65%. For coals that must meet less stringent standards, like some steam coals, recovery rates can range up to 85%.
- *The capital, operation and maintenance costs associated with construction and operation of coal preparation plants.* Sophisticated plants to provide high quality steam and coking coals cost up to $68,000 per tonne-per-hour (tph) of capacity. A preparation plant designed to process 2 to 3 million tonnes of coking quality coal per year can cost as much as $40 million.

As with coal-extraction costs, preparation costs are dictated by site-specific conditions. The coal producer's resources and the end-user's needs dictate the ultimate amount and cost of coal preparation. Table 4.5 illustrates the cost differentials between different levels of coal preparation.

Coal preparation offers advantages to the end user and enables the producer to command a higher market price for his product. Among the advantages:

- Coal washing removes inert material which offers little or no energy, thus increasing the coal's calorific value. This reduces transportation costs per unit of energy and improves combustion performance.
- Coal washing helps avoid expensive post-combustion processes to remove impurities, such as ash and sulphur, that cause environmental degradation.
- Advanced coal washing provides a uniform product that can meet the stringent ash, calorific-value and size standards for coking and combustion in some boilers.[12]

12. IEA Coal Research (1986).

Table 4.5: **Comparative Costs of Differing Levels of Coal Preparation, 2000**

Level	**Capital,** ($ per tonne-per-hour)	**Capital,** ($ per tonne)	**O & M** ($ per tonne)	**Total** ($ per tonne)
Crushing and screening	8,640	0.29	0.11	0.40
Rotary breaker	7,360	0.25	0.09	0.34
Coarse cleaning only	1,520	0.50	0.28	0.78
Coarse and simple fine cleaning	22,800	0.76	0.67	1.43
Coarse and fine cleaning & flotation closed circuit	31,680	1.06	1.11	2.16
Cleaning all sizes, fine crushing, multi-stage closed circuit	63,360	2.10	2.22	4.32
Cleaning all sizes, fine crushing, multi-stage closed circuit with thermal drying	68,000	2.66	2.84	5.49

Source: IEA analysis.

Productivity

The improvement in labour productivity in the main coal-producing countries has been a major reason for the decline in real coal prices at the mine-mouth since the early 1980s. Between 1980 and 1999, average labour productivity in eight major coal-producing countries, Australia, Canada, Colombia, Germany, Poland, South Africa, the United Kingdom and the United States, increased on average by 7% per year. The rate of productivity improvement has accelerated; between 1998 and 1999, productivity in these countries increased by 15%.[13]

A recent study by the US Energy Information Administration (EIA) examined the factors which have contributed to improvements in productivity:[14]

- A shift to regions with thick-seam coal reserves that can accommodate large-area surface-mine technology. This has occurred in Colombia, Indonesia, the US and Venezuela.
- Strong interfuel and intrafuel price competition, coupled with excess production capacity for some coal types, has closed down less efficient and smaller producers. This has occurred in Canada, Europe, and the US.

13. IEA (2000a).
14. EIA (2001b).

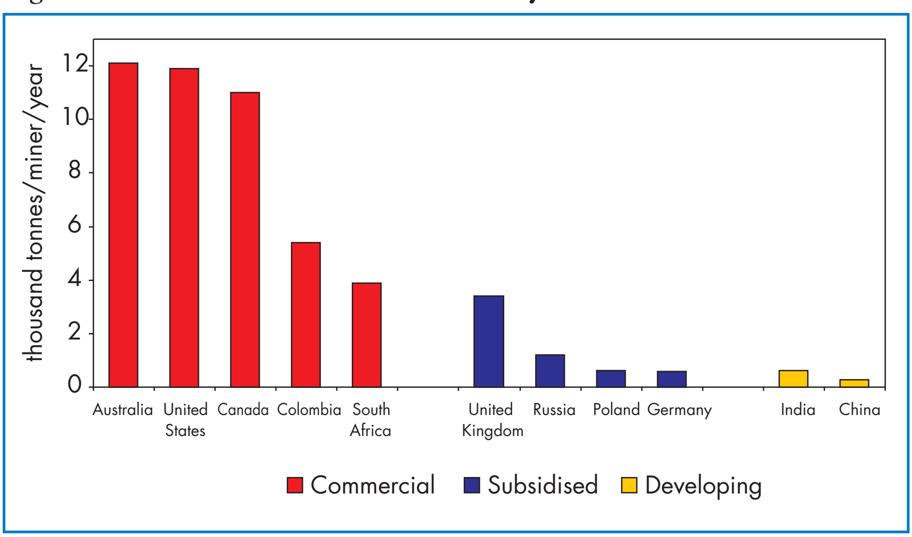
- Technological advances throughout the coal industry have increased productivity and have more than offset resource depletion. This is the case in Australia, Canada, China, Eastern Europe, India, South Africa and the US.

The EIA study found that mine scale has a significant effect on labour productivity and on unit costs. From a financial point of view, it makes sense for private and public investors to support the consolidation of large coal reserve blocks, as this practice can justify the multi-million dollar investments that large-scale, advanced coal mining requires.

Declining coal prices can also have a major effect on wage rates and productivity. The EIA study shows that, when coal prices increased more rapidly than wages, labour productivity declined, as smaller, less geologically favourable mines were opened. Many of those mines were forced to close within several years when coal prices fell. Conversely, when coal prices declined faster than wage rates, or when wages were rising, labour productivity grew, as coal producers sought to maximise their return on labour.

As Figure 4.8 shows, labour productivity is highest in countries where the coal industry is exposed to the competitive pressures of the international market. In countries with a long history of coal-industry subsidisation—either through price and cost supports, in the UK,

Figure 4.8: **Coal Mine Labour Productivity in Selected Countries, 1999**



Source: IEA (2000).

Germany and India, or through socialisation of costs, in Poland, Russia and China—labour productivity is significantly lower.

Two factors will continue to stimulate improvements in labour productivity:

- The scale of individual mines will continue to increase, especially in developing countries and in countries active in the international coal market.
- Coal extraction, preparation and transport technology is expected to improve. This will permit even larger-scale mining units and more efficient utilisation of labour.

Scope remains for further gains in productivity in the international coal industry. These can be obtained through economies of scale, exploitation of contiguous resources and further improvements in working practices and labour productivity. But these improvements require time, management skills and capital. In major coal-producing countries, growth in labour productivity averaged between 5% and 10% in the 1980s, and from 10% to 15% in the 1990s. Continued evolution in size and improvements in mining technology will yield rates equal to, or higher, than this in the future, as coal producers adopt advanced mining approaches.

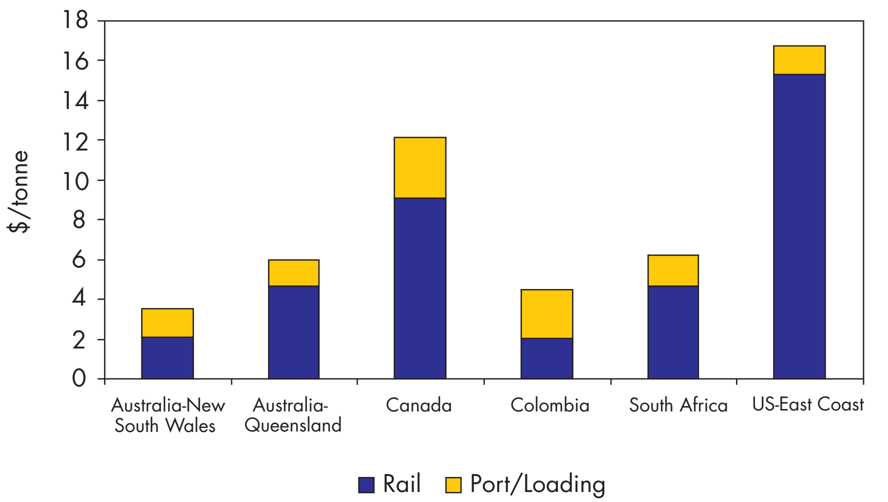
Coal Transport Costs

Coal-transport costs can represent a significant proportion of the total cost of supplying coal to end users. These costs have a major impact on the delivered price of coal and hence on coal demand, as well as the geographic range of coal markets. Most of the world's coal is consumed close to where it is mined because long-distance transport is very expensive.

Transport of coal for domestic consumption can be by rail, truck, conveyor belt, barge or domestic intra-coastal ships, or by a combination of methods. In large countries like China, India, Russia and the United States, domestic coal movements may range from 500 to 2,000 kilometres, and may cost from $7 to $25 per tonne. In some cases, transportation costs are significantly more than the price of the coal at the mine-mouth. In smaller countries like Germany, Italy, Poland, Spain and the UK, coal is often moved by rail or barge. Coal transport costs in Germany range from $3 to $7.50 per tonne.

Regardless of the distances involved, a well-developed transportation infrastructure is needed to handle large-volume movements of bulk coal. Constraints on transportation infrastructure continue to plague developing countries like China and India, and even some more developed countries like Russia. Even in the most advanced coal-producing countries, transportation infrastructure problems can disrupt coal supply.

Figure 4.9: **Average Inland Transport Charges**



Source: IEA analysis.

The transport cost of internationally traded coal is often very high. It requires the construction and operation of rail and barge corridors, transloading facilities at the ports of exit and receipt and seaborne ships capable of hauling bulk commodities. Inland transport costs are similar to those for domestically produced coal, although these costs can be lower in countries with large coal export industries that have dedicated rail and terminal facilities. Average inland transport charges in some countries, including loading charges, are summarised in Figure 4.9. The data are meant to be illustrative rather than definitive.

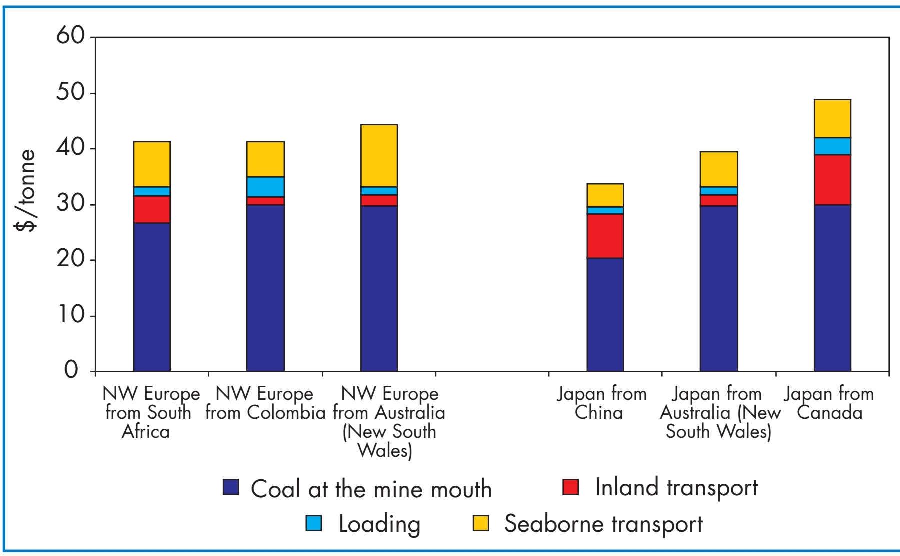
In January 2001, dry bulk commodities were transported in ships with an estimated capacity of 276.7 million deadweight tonnes.[15] In addition, 36.6 million deadweight tonnes were on order for delivery within the next three years. The fleet carries dry bulk commodities like iron ore,

15. Deadweight tonnes describes the carrying capacity of a ship.

phosphate, alumina bauxite and grain, as well as coal, which is the largest volume dry-bulk commodity handled.[16]

Figure 4.10 illustrates the relative size of each component of delivered steam-coal prices into northwestern Europe and Japan in June 2001. The data were derived from reports in the trade press, and do not refer to specific coal transactions. Transport costs represent between 25% and 40% of the total delivered cost of the coal. The delivered cost is quoted at a point prior to unloading. In addition, it costs from $3 to $10 per tonne to move the coal to its final point of consumption. Thus, for steam coal, more than 50% of the total delivered cost could be attributable to transport costs. In the long term, transport costs are not expected to constrain coal supply.

Figure 4.10: **Components of Delivered Import Steam Coal Costs**



Source: IEA analysis.

Pricing and Industry Developments

Coal Pricing

The coal market functions in a generally competitive and commercial context, the market matches consumers with suppliers, and most companies are privately owned. Direct government intervention is fairly

16. *World Bulk Fleet and Review 2000*, Fearnely's, Oslo, February 2001.

limited. But some European countries, as well as India, China, Russia and Japan, have policies which do not necessarily promote the most economically efficient supply.

International coal trade has developed over the last 30 years and accounts for about 12% of world coal supply. Local production for local use remains the norm. However, domestic performance is increasingly assessed against the price and productivity standards of the international market, and a single world coal market can be said to exist as far as global coal-price relationships are concerned.

Prices in the two key regional markets—Europe-Atlantic and Asia-Pacific—have historically been closely linked. Coal from any of the major exporters may find a market in either Europe or Asia, depending largely on transport costs. The Pacific market is supplied mainly by Australia, Indonesia and China because of geographic proximity. South Africa, Poland, the US, Colombia and Venezuela are the primary suppliers to the Atlantic market. The two markets have traditionally been linked by South Africa which faces mid-range transport costs to both markets. The US has had the capacity to make surpluses available for export to Europe, when the international price is higher than the domestic price. Thus, it acts as a swing supplier to European consumers and often sets a price cap in the Atlantic market. Australia has a secondary role as a swing supplier to Europe, when coal market conditions and transport costs are favourable and when the US coal industry is unable to play the swing-supplier role. South Africa's geographic location enables it to supply both Asia and Europe, thus ensuring that price signals are transmitted between the Europe-Atlantic and Asia-Pacific markets.

On the demand side, Europe's importance in the Atlantic market as a marginal consumer of coal has been matched by Japan's importance in the Asia-Pacific market in establishing a reference price for that market. Prices have traditionally been set through individual transactions between suppliers and consumers. Larger companies sell their coal directly to consumers, although some traders play a role in matching supply and demand. Coal markets, unlike those for many other commodities, have usually functioned on the basis of a close network of long-standing relationships between suppliers and consumers. Long-term supply contracts of ten to fifteen years used to be the norm, reflecting the long-term investment decisions that mines, transport and transport logistics required. Within this long-term supply framework, annual price negotiations took place for contract supplies to Asian and European consumers.

Through 1997, contract negotiations between Japan and Australia for coking coal established a benchmark price that was used later in the year to set contract prices for steam coal. This system, which was driven by Japanese concerns about security of supply, has now been replaced by a more competitive approach. Asian consumers, in particular Japan, are moving to the system used in the Atlantic market where annual contracts, supplemented by spot purchases, are the norm. The Asian consumers have a slightly different approach of public bids relayed via the coal press, a system rarely used by European consumers.

Both regional markets are experiencing a rapid evolution of the spot market for steam coal. Spot transactions can be for one cargo or for a series of cargoes but do not necessarily involve a long-term relationship between suppliers and consumers.

Although the end of benchmark pricing and the development of the spot market represent a significant move towards more competitive and efficient coal markets, there is no international coal exchange equivalent to other commodity exchanges. This may be explained by the importance of quality differentials for most coal consumers, especially for coking coal (Box 4.2). Trial shipments and testing for particular steel mills and power plants remain common.

International steam coal markets, which account for two-thirds of international coal demand, are strongly linked to electricity markets, as the power generation sector is the primary consumer of steam coal. The demand from power generators is a key influence on steam coal prices. This links the steam coal and the oil and gas markets because power generators can substitute between fuels based on relative prices. International steam coal demand increased in 2000 not only because several new coal-fired power plants were commissioned in Asia, but also because coal was substituted for high-cost oil and gas by power generators throughout the world.

In the case of coking coal, price trends can be attributed to the demand for steel. The coking-coal price cycle is also affected by developments in coke-making technology, coking capacity and changes in fuel choices for integrated steel making.

The worldwide availability of coal at reasonable cost and the relative ease with which major producers can enter or exit the international market make any significant and sustained price increase unlikely. At the same time, improvements in productivity have lowered overall production costs, and the export capacity of major producers has increased. Coal markets are competitive, and competition will be encouraged further with the liberalisation of electricity markets.

Box 4.2: **Coal Quality**

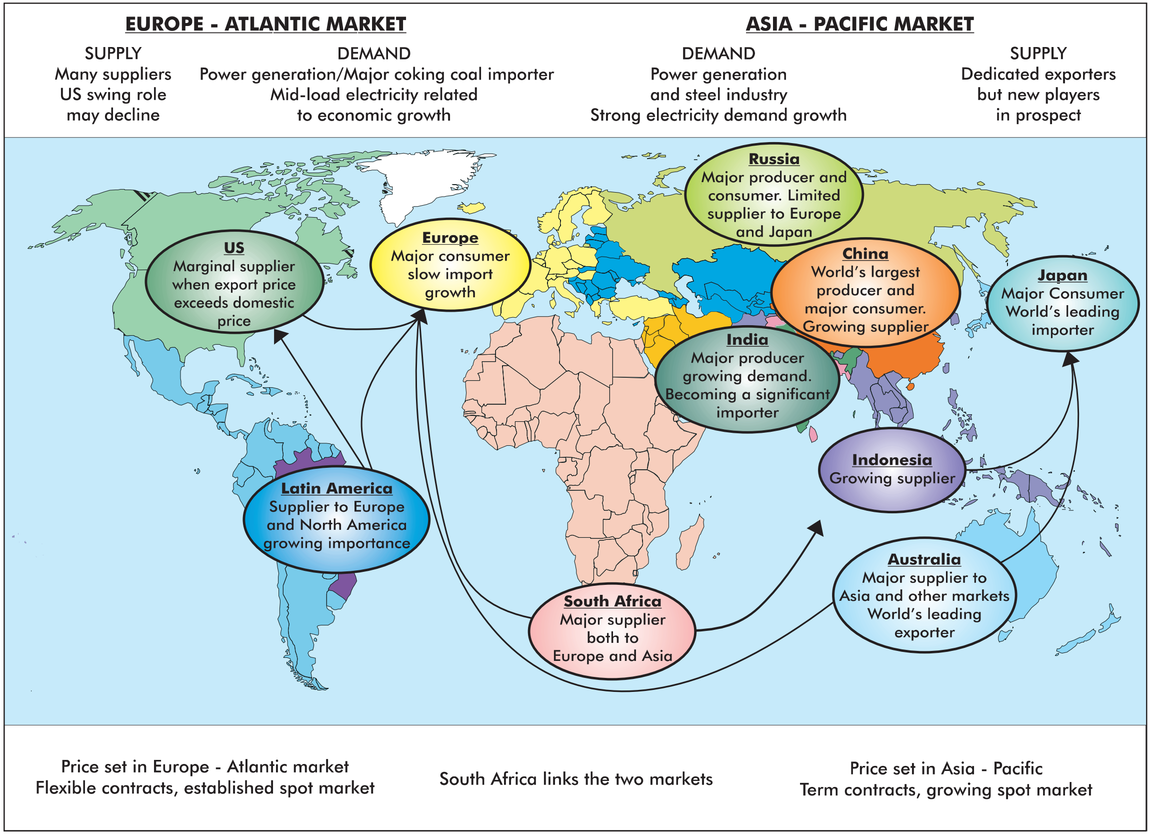
In steel-making, coking coal characteristics are critically important and extensive tests are undertaken before a coal brand is accepted by the market. For power generation, a wider range of coal qualities is acceptable, but power-generation performance can still be affected by coal quality. Laboratory-scale coal tests have shortcomings and may not be relied upon by a plant operator until adequate tests are performed in the plant. Steam coal properties of greatest concern to operators include:

- ash content and composition,
- heating value,
- sulphur content,
- moisture content,
- grindability,
- volatile-matter content.

These factors can influence price through a system of premium/penalties. They may affect operating and maintenance costs, and therefore the cost of electricity production.

Over the long term, coal prices are expected to remain flat. But short-term fluctuations in prices, influenced by international market conditions, will occur. The end-2000 and 2001 price trends, reflected in both contract and spot transactions, are strongly upward for both steam and coking coal. Steam coal prices set for deliveries in Asia and Europe for 2001 have been 20% to 25% higher than prices for similar quality coal delivered in 2000. For hard coking coal, negotiations between Japanese steel makers and Australia coal producers, concluded in February 2001, set prices 5% to 11% higher than in 2000. These price increases were also reflected in settlements with steel-makers in Europe, India and Latin America.

Figure 4.11: **International Coal Trade Relationships**



Source: IEA analysis.

Coal market observers have attributed the recent price rise to several factors:

- A large drop in coal inventories at power plants, coupled with two years of coal-production declines, reduced steam-coal exports and increased steam-coal imports in the US. This caused a tightening of supply in the Europe-Atlantic market and boosted prices.
- Strong steam and coking coal demand growth in the Asia-Pacific market due to new power plant additions, high economic growth and high substitute fuel prices.
- Strong steam-coal import demand growth in the Europe-Atlantic market due to declining domestic production and high substitute fuel prices.

The *WEO 2000* assumes that international coal prices will remain flat in real terms over the next 20 years. The OECD steam coal import price is assumed to be $46.50 per tonne (2000 $). While this is higher than prices in 1999 and 2000, it is consistent with the long term steam coal import prices experienced from 1980 to 2000 (Figure 4.2). Improvements in productivity and technological advances will continue to lower overall coal production costs. Increasing competition will also play a role. However, the effect on prices will be offset by higher shipping and handling costs, resulting mainly from an assumed increase in oil prices after 2010.

Coal will be traded in an increasingly competitive market context, and new producers and traders will enter the market. Continued liberalisation of pricing arrangements will occur. The Asian market is following the lead of the Atlantic market with more flexible contracts and with a growing use of spot purchases. The reference price system has virtually disappeared. The current lack of international coal exchanges will be compensated by the development of e–business.

The lack of exchanges that distinguishes coal from other commodities is a major factor driving interest in e–business. Two routes are currently in early development. The first consists of a trading system where players can buy and sell physical or financial quantities of coal through an electronic market, two of which are currently in operation. The second consists of physical coal sales through an e-auction platform. This system officially started in December 2000 when the Japanese utility Tohoku Power accepted bids. Other coal consumers and producers continue to experiment with this approach.

Commercial Hard Coal Industry

The structure of the international commercial hard coal industry has changed significantly over the past ten years. Coal companies have consolidated and diversified, and ownership changes have made the industry more global. The US firm Peabody remained the largest coal producer throughout the 1990s, but the rank of many other companies was affected by mergers and acquisitions. In 1995, Cyprus Amax was the second largest coal producer, with 75 million tonnes, and Ingwe Coal in South Africa was third, with 70 million tonnes. Today, Cyprus Amax is part of the German company RAG, and Ingwe Coal is a subsidiary of Billiton in the UK.

The ten largest commercial hard coal companies account for roughly one-quarter of total world hard coal production (Table 4.6). If the production of large state-owned companies in India and China is taken into account, this share increases to some 60%. Production under the control of the three largest companies grew considerably from 1995 to 2000, the result of acquisition rather than a real increase in output. Coal production by the world's largest producer, Peabody, grew by 35% from 1995 to 2000.

Table 4.6: **Ten Largest Commercial Hard Coal Companies, 2000***

Companies	Production (Mt)	Exports (Mt)	Ratio of exports to production(%)
Peabody (US)	176	11	6
Rio Tinto (UK)	132	25	5
Arch Coal (US)	106	4	4
RAG (Germany)	97	7	7
Billiton (UK)**	69	34	50
Anglo Coal (UK)	65	23	36
Consol (US)	63	9	14
BHP (Australia)**	54	35	65
Sasol Mining (South Africa)	51	4	7
Glencore (Switzerland)	39	31	79
Ten Largest	**852**	**183**	**21**
World Total	**3,638**	**591**	**16**

* preliminary figures.
** Billiton merged with BHP in 2001.
Source: IEA (2001a).

Most large acquisition activity has been international.[17] The global acquisitions of the major producers have resulted in a shift in the relative importance of countries that often does not reflect their actual production ranking. Three UK companies are among the ten largest producers, yet the UK is a minor producer. The presence of three US companies in the top 10 underlines the continuing importance of this country as a producer and international player. In 2000, the ten largest companies shown in Table 4.6 represented a large share of production in many countries (Figure 4.12). In South Africa, Billiton, Anglo, Glencore and Sasol produced 87% of total coal output. In Australia, 46% of production is owned by the producers in the top ten.

The coal industry has developed rapidly in size and global reach. Global revenue from the ten largest producers is some $18 billion.[18] But this is still small compared with oil industry revenues. The largest private company, Exxon Mobil, has global revenues of $185 billion, ten times the combined revenues of the ten largest coal companies.

The recent wave of consolidations has made the coal industry more diversified. Most of the large coal companies are no longer exclusively concerned with coal. They are multi-commodity or multi-activity companies. Shareholding has also diversified. The shares of eight companies are traded on stock exchanges in New York, as well as Sydney, Johannesburg and London. Some company shares trade on more than one stock exchange, reflecting the pattern of acquisitions.

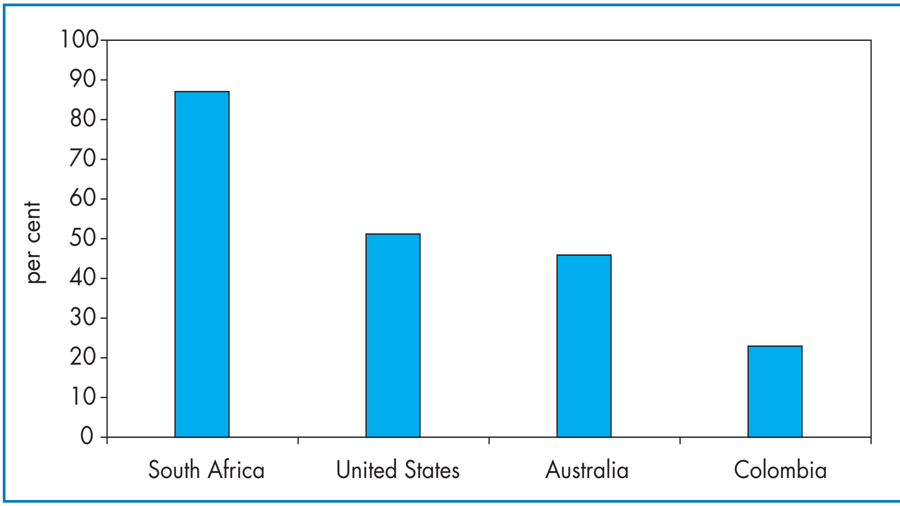
The coal industry is catching up with the general evolution of energy markets toward greater complexity, diversity and concentration at a global level. The implications of these changes will be very important. A trend toward oligopoly is emerging. In South Africa, for example, three companies control nearly 90% of exports.

Coal companies are also becoming more geographically diversified. The world's main production companies now have stakes in many different countries. In the future, coal companies are bound to pay more attention to costs, to search for geographic diversity and to examine closely their companies' stock-market performance.

17. The two largest US companies, Peabody and Arch Coal, located in the eastern US, have purchased new production assets in the western US. Even this represents a shift in focus, however, given the substantial difference in coal production between the eastern and western US.

18. This figure takes into account government subsidies received by the German company RAG for its domestic production.

Figure 4.12: **Share of the Top Ten Commercial Producers in Total National Production**



Source: IEA (2001a).

Government Policies

Although the coal market is competitive overall, a number of government policies influence it. Environmental policies are rapidly growing in importance. Some countries continue to subsidise coal production or consumption, directly or indirectly. Government policies that influence the sector also include employment and safety legislation and transport policies, especially for rail. These policies can have a significant impact on costs, on royalties and taxes and on the decisions by producers whether to sell in the domestic market or to export.

The role of coal in future energy supplies has recently re-emerged as a major issue in many countries. In a recently published Green Paper *"Towards a European Strategy for the Security of Supply"*, members of the European Union recognised the importance of coal as a secure energy source. Recent discussions in the US have made the same point. Dependence on imported gas and oil will rise in the future, and the role of coal in energy diversification and security of supply seems likely to become more prominent.

Environmental Policies

Despite the security-of-supply advantages that coal provides, it faces many challenges in meeting environmental mandates. Governments are imposing increasingly strict requirements on the coal supply chain, from mining to transport, and on the use of coal in power generation and steel-making. This reflects a general tightening of environmental standards for all energy sources. But it also reflects the fact that coal supply and consumption can cause environmental damage. Clean-coal technologies (CCTs) have been developed, and continue to be developed to meet the growing environmental challenge.

Coal extraction, particularly from surface mines, disrupts the natural landscape and produces large quantities of waste. Clean technologies for the extraction of coal are now available. Improved exploration methods using geophysics and seismic techniques can minimise environmental impact and improve mine planning by reducing geological uncertainties. In most OECD countries, cleaner technologies are widely used to reduce noise, dust levels and methane emissions. Mine planning routinely includes provisions to avoid the risk of ground-water contamination. In some cases, provision is made for backfilling of mined space with coal washery discard, power-station ash or other residues.

In many OECD countries, considerable attention has been paid to land restoration once mining activities have ceased.[19] Plans for new mines are routinely required to include provision for effective waste management and site rehabilitation. These provisions apply both to underground and surface operations, although, in the latter case, it may not always be economically feasible to restore the land to its original contour.

Site rehabilitation may enhance land value. In older mine areas, where mining has left a legacy of spoil heaps and industrial waste, modern rehabilitation techniques have been used to restore land for farming, building or recreation. In mountainous areas, modern surface mining using mountaintop removal and valley-fill methods can create extensive areas of level land for arable use.

Coal transport and storage also cause environmental damage from dust and noise, and modern techniques have been developed to minimise these problems. In urban areas, coal can now be delivered pneumatically, through pipes to enclosed silos on congested sites inaccessible to vehicles. Most current coal-exporting terminals have already taken measures to limit

19. IEA/DTI (1999).

dust emissions. To capture dust from stockpiles, coal terminals water it, and recycle the polluted water.

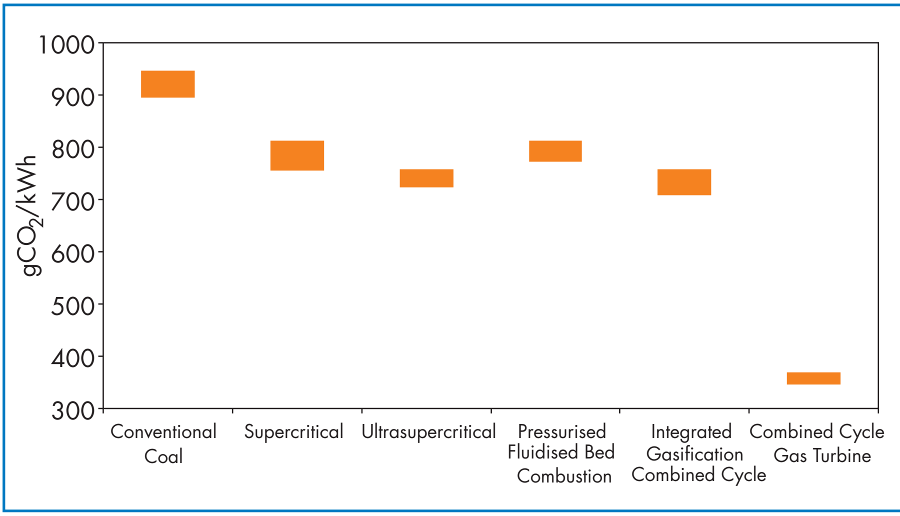
Clean coal technologies for power generation can reduce the environmental impact of coal-fired power generation. These technologies are:

- *Supercritical*: power generation in which pulverised coal is burned in a boiler at atmospheric pressure with steam conditions above 22.12 Mpa.
- *Ultra-supercritical*: supercritical plants which have a maximum steam temperature above 566°C or a maximum steam pressure above 24.8 Mpa.
- *Atmospheric Fluidised Bed Combustion (AFBC)*: plants in which coal is burned in a fluidised bed, bubbling or circulating, at atmospheric pressure, and the heat is recovered to power a steam turbine.
- *Pressurised Fluidised Bed Combustion (PFBC)*: a process that includes fluid-bed combustion at pressure, hot-gas clean-up, steam-turbine and combustion-turbine generation.
- *Integrated Gasification Combined Cycle (IGCC)*: a process that includes coal gasification, hot-gas clean-up, steam-turbine and combustion-turbine generation.

All of these technologies offer significant improvements in efficiency and environmental performance compared with conventional subcritical pulverised-fuel technologies (Figure 4.13). There are a number of barriers to the adoption of clean coal technologies. The most important of these is their high cost. Government policies, such as heavier research and development spending, could eventually overcome these barriers. Over the next two decades, clean-coal technologies could become cost competitive with combined-cycle gas turbines, the current favoured option for power generation.

Key long-term uncertainties facing investors in the commercial coal industry are the risk of increasing competition in the power sector and the likelihood of more stringent environmental controls, especially those aimed at meeting the carbon-emission reduction targets in the Kyoto Protocol. The prospects for coal-based power generation depend, in the first place, on the adoption of cleaner and more efficient technologies in OECD countries and, in the longer term, this adoption in developing countries. Such technologies are already available, but they require widespread commercial demonstration.

Figure 4.13: **CO_2 Emission Factors by Technology (Current and Near-Term)**



Source: IEA Coal Research (1999), UNDP, UNDESA and WEC (2000), and IEA.

Subsidies and Restructuring Policies in OECD Countries

A number of hard-coal producing countries in the OECD provide varying measures of financial and other support to their indigenous producers. Coal industries in the Czech Republic, Germany, Poland, Spain and the United Kingdom were once the mainstay of local economies. But much European coal is found in deposits which have thin seams and lie at extreme depths. As the development of the international coal trade made cheaper coal available, several governments sought to maintain their coal industries by providing production subsidies.

The IEA measures this aid by calculating a Producer Subsidy Equivalent (PSE)—a payment that keep domestic production competitive with imports at existing levels of coal output, current producer incomes and import prices. Table 4.7 shows the breakdown of production for 2000 in the countries for which IEA has calculated a PSE.

The amount of OECD hard-coal production receiving government support, as measured by the PSE, has declined over the past decade, both in absolute and per centage terms. The aid-per-tonne equivalent in US dollars for IEA countries with subsidised production (excluding countries such as the Czech Republic and Norway which have very small subsidies) is shown

Table 4.7: **Subsidised Hard Coal Production in the IEA, 2000***

	Million tonnes of coal equivalent	**Percent of IEA total coal production**
France	3.2	0.3
Germany	34	3.0
Japan	2.8**	0.3
Spain	10.4	0.9
Turkey	1.7	0.2
UK	27.5	2.4
Total subsidised	**79.6**	**7.1**
Non-subsidised	**1 048.8**	**92.9**
Total IEA production	**1 128.4**	**100**

* Preliminary figures.
** Japanese data are for 1999.

in Table 4.8. Subsidised production is now concentrated in Germany and Spain. Germany accounts for 68% of PSEs and 43% of subsidised production.

Since the early 1990s, coal producers in Poland and the Czech Republic have been reviewing the competitiveness of their industry and engaging in substantial restructuring programmes. The main objectives are to close down unprofitable mines, to restore other mines to profitability and to identify economic opportunities for further mine development. In most cases, viable mines are to be privatised.

Firm plans for subsidy reduction exist in many countries. France expects to close its domestic industry by 2005. Japan plans to phase out subsidies by 2006. Germany is expected to reduce subsidises and subsidised output by one-third by 2005. The UK's decision last year to reinstate subsidies to its coal industry only covers a short period, from April 2000 to July 2002. Spain expects to reduce subsidised production by a further 20% by 2005. By 2006, only Germany, Spain and the relatively small Turkish industry plan to continue subsidies.

Subsidies will not be completely eliminated in the foreseeable future, however. In the EU, the approaching expiration of the Coal and Steel Community Treaty in July 2002 is forcing a review of the case for continued subsidies. The EU suggests that subsidies could be used to maintain effective access to coal reserves in order to maintain security of coal supply. The EU adopted a new proposal in July 2001 that establishes

Table 4.8: **Total Producer Subsidy Equivalent for Coal Production in Selected OECD Countries**

(Production in million tonnes of coal equivalent; aid in US dollars)

		1999	2000*
France	Production	4.1	3.2
	Aid per tce	91.76	97.15
Germany	Production	40	34
	Aid per tce	118.2	115.4
Japan	Production	2.8	n.a.
	Aid per tce	134.29	n.a.
Spain	Production	10.3	10.4
	Aid per tce	72.92	70.32
Turkey	Production	1.5	1.7
	Aid per tce	155.8	220.95
United Kingdom	Production	32.1	27.5
	Aid per tce	0.00	3.25

* Preliminary figures.

Note: Tonne of coal equivalent (tce) is a standard unit of measurement in the international coal industry, having an energy value of 29.3 GJ/tonne or 7,000 kcal/kg. One tonne of coal equivalent is equal to 0.7 tonne of oil equivalent (toe). The actual relation between physical tonnages and tce differ for each producing country, and averages for each year are published in *IEA Coal Information.* For example, in 1996, 1 tce amounted to 1.19 physical tonnes of indigenous steam coal in Germany.

rules for the continuation of state aid after expiration of the European Coal and Steel Community Treaty. The regulation will apply from July 2000 to 31 December 2010.[20] EU member states will be allowed to grant aid to maintain access to coal reserves.

Subsidies and Restructuring Policies in non-OECD Countries

Subsidies, often offered to consumers rather than producers of energy, are used in many non-OECD countries. A recent IEA study confirms the underpricing of energy resources in eight of the largest energy-consuming countries outside the OECD: China, India, Indonesia, Iran, Kazakhstan, Russia, South Africa, and Venezuela.[21] On average, end-use prices in these countries are 20% below the market reference price.[22] Developing

20. European Commission (2001).
21. IEA (1999).
22. The market reference price corresponds to the world market price taking into account transport and other costs, or if there is no world market, the full production costs.

countries frequently keep prices below the cost of supply to encourage commercial energy use by the largest possible number of people.

Artificially low prices are a key cause of the poor financial performance of many state-owned energy companies. This poor performance seriously reduces the companies' ability to invest to meet increasing demand. It also discourages private and foreign investment. Most of these countries have therefore embarked on energy reforms aimed at increasing the role of the market. Subsidy reduction and the removal of price controls are usually central features of these policies.

Regional Analysis

China

Market Overview

Coal accounts for more than 70% of primary energy consumption in China. Demand for coal increased five-fold from 1971 to 1996, by nearly 5% per year, the result of sustained economic growth and the associated increase in power-generation demand. Coal consumption declined in 1997, however, and continued to fall in 1998, 1999, and 2000. The recent decline was primarily in the end-use industrial and residential sectors, rather than in the power generation sector. A recent study[23] attributes the decline in Chinese coal consumption to the following factors: structural changes, reform of state-owned enterprises, stricter environmental regulations and enhanced energy efficiency. China is still the world's largest coal-consuming country, but its share in total world consumption has fallen by over 5% in the last five years.

The implications of recent trends in Chinese coal consumption cast some uncertainty over future demand prospects. The Chinese government's stated priority in its 2001-2005 energy plan is to rationalise the energy supply structure in China. This will involve increasing the share of cleaner and more efficient energy sources like natural gas and hydropower and decreasing the share of coal. Coal consumption is still likely to rise in the future, although at a slower rate than before. Over the next twenty years, projected coal demand growth will average 2.6% annually, and demand will reach nearly 2.7 billion tonnes by 2020. Most of the increase will be for power generation, although coal for the

23. Sinton, J.E. and Fridley, D.G. (2000).

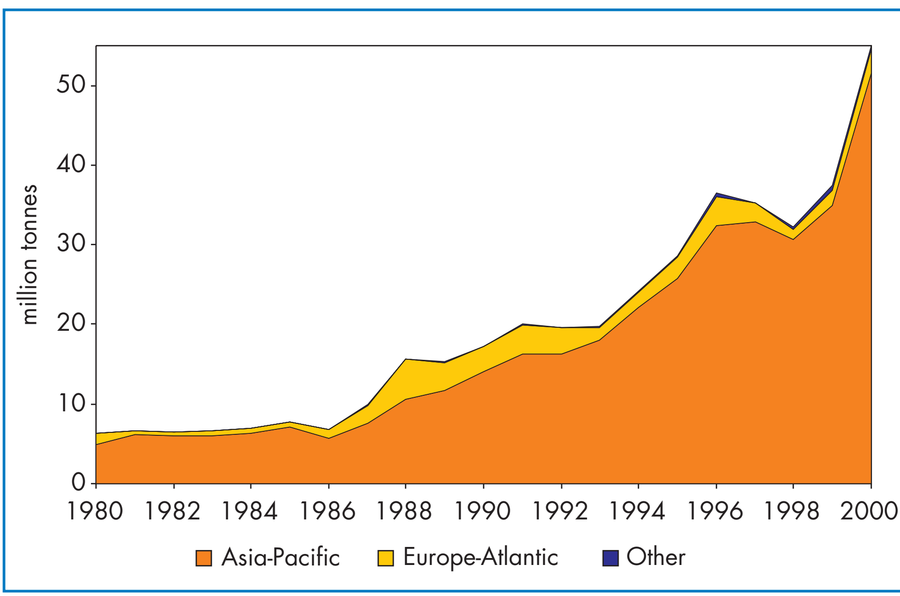
manufacture of coke for industry will remain important. In 2000, China was the world's leading producer of both steel and pig iron.

The coal industry has faced severe problems of over-supply. The Chinese government has begun to shut down illegal, dangerous and polluting mines, most very small in size. At the end of 2000, the government claimed that over 47,000 loss-making, small mines had been closed. Coal receives indirect subsidies through transport subsidisation, with the price of rail transport about 20% lower than actual cost.[24]

Exports

Current Chinese policy is to expand the country's coal-export capacity. A reduction of port charges and a recently-enacted exemption of export-coal shipments from railway construction tolls on major transport routes were both explicitly designed to stimulate export growth. Coal exports, mostly steam coal, increased sharply between 1999 and 2000, from some 37 million tonnes to over 55 million tonnes. In 2001, Chinese coal exports may exceed 80 million tonnes.

Figure 4.14: **Chinese Coal Export Growth by Destination**



Source: IEA.

24. ABARE and ERI (1999).

Japan and South Korea take over 60% of China's exports. The Philippines and Chinese Taipei have also become substantial importers of Chinese steam coal. The surge of Chinese steam coal exports in 2000 and 2001 has dampened coal-price growth in the Asia-Pacific market. Chinese steam coal entering the Europe-Atlantic market in the second half of 2001 may have dampened coal prices in that market as well. There are good prospects for Chinese coal producers to capitalise on their proximity to the Asia-Pacific market. But it is not yet clear that the Chinese coal industry can meet anticipated *domestic* demand, and also continue to expand exports.

While it has been rationalising its coal industry, China has encouraged the development of world-class coal mines by opening some of its coal-producing areas to international investors. There is now an expanding domestic market for advanced coal mining technology and a growing cadre of highly-qualified mid-level management. Foreign investment, however, will only be attracted to the Chinese coal sector if there are major changes in property laws and export rights, and in regulations on coal transportation and the repatriation of profits.

To the extent that Chinese expansion into international coal markets prevents other countries from developing competitive coal production capacity, Chinese export policy could prove detrimental to the international coal sector. However, use of the international market as a benchmark for domestic coal-industry performance could also have a beneficial impact on domestic coal supply and price. Expanding exports along the trend set in 2000 and 2001 will require further large investment in transport and port infrastructure, and the continuation of government assistance to coal producers. Based on *WEO 2000* projections, Chinese coal exports could rise to about 100 million tonnes in 2020.

In addition to being a major player in the world coal export market, China, mainly Hong Kong, also imports large quantities of coal. In 1999, China imported over 8 million tonnes of hard coal, mostly from Australia. Chinese imports in 2000 are estimated to have been slightly higher than in 1999 and this trend could continue to increase in the future. In the long-term, imported coal could become economic in other regions of China, if transport subsidies are reduced further. The domestic price of coal in the southeast is less than the cost of production and delivery. Because of the vast distances between coal consuming and producing regions, transport costs account for some 50% of the delivered cost of coal in southeastern China.[25]

25. ABARE and ERI (1999).

Reserves and Production Outlook

China has some 114.5 billion tonnes of proven coal reserves, nearly 12% of the world total. Steam coal accounts for 83% and coking and gas coals[26] for the remainder. The proportion of coal reserves available to depths of 150 metres is limited; future production will need to focus on underground operations, which are often more costly and sometimes less productive than surface mines.

Chinese coal production more than doubled from 1980 to 1996, but declined from 1997 through 2000. Estimated production in 2000 was 1,171 million tonnes, some 5% below 1999. Between 2000 and 2005, Pingsu Coal's Anjialing surface operation will enter full production, adding 15 million tonnes per annum to production capacity. Yinzhou Jining III mine will expand to full production of 4 million tonnes, and the new Juye mine will add 4 million tonnes to capacity. Datong Bureau (Shanxi) will complete the Sitaigo Mine adding 5 million tonnes per annum to capacity. The Shenhua Group is planning to expand production capacity to 60 million tonnes per annum by 2005. Other expansions in Anhui, Hebei, Shandong and Shanxi will add another 10 million tonnes to capacity.

Chinese mining productivity is very low by international standards, but labour in coal mines is being steadily reduced. Coal production assets, transport infrastructure and resources will undoubtedly be subject to further rationalisation to meet domestic and export needs. Some 42 billion tonnes of demand is projected for China over the next twenty years. Fulfilling this demand solely with domestic production will deplete about 37% of current proven coal reserves. China added only 15.6 billion tonnes to its proven reserves in the last 22 years. An increase in proven reserves will be needed to support projected domestic demand.

United States

Market Overview

In 2000, US coal demand was some 971 million tonnes, 0.6 % higher than in 1999. About 90% of US coal consumption is used for electricity generation. The share of coal is roughly half of total generation. Coal's share in total primary energy supply will decline slightly, as some coal is

26. Gas coals include lower quality coals and brown coal/lignite which can be gasified in gasworks to make coal gas (often substituted for natural gas).

displaced by oil and gas in the industrial, commercial and residential sectors. Prospects for coal-fired generation depend on developments in combustion technology (for both coal and gas), on environmental regulations and on relative fuel prices. But rising natural-gas prices and the retirement of nuclear plants are expected to increase demand for coal-fired baseload capacity.[27] Primary coal demand is expected to rise in the period to 2020, with the bulk of the increase going to power plants.[28]

Exports

The United States was the fifth largest coal exporter in 2000, behind Australia, South Africa, Indonesia and China. US coal exports have fallen precipitously since 1995, due mainly to increased competition from other coal-producing nations and to low international prices that have dampened US coal producers' willingness to ship in the international market. Hard-coal exports were 53 million tonnes in 2000, nearly 7% lower than in 1999. Exports of coking coal recovered marginally from 29.1 million tonnes in 1999 to 29.8 million tonnes in 2000, but steam-coal exports declined 18.3% to 23.2 million tonnes. The US Energy Information Administration projects that the role of the US as a swing supplier to the international coal market could decline as a result of domestic power-capacity needs and tighter US supply conditions. *WEO 2000* projects US coal exports of some 72 million tonnes in 2020; coking coal exports will be some 38 million tonnes.[29]

Reserves and Production Outlook

The United States has enormous coal resources. According to the WEC *Survey of Energy Resources 2001*, the US possesses 250 billion tonnes of proven reserves of hard coal and lignite, over 25% of total world proven reserves. Production of US hard coal, including bituminous, sub-bituminous and anthracite, declined for the second consecutive year in 2000, falling to 899 million tonnes. This was the first time in forty years that there have been two consecutive years of declining coal production.

Production in the eastern United States has declined since 1997. Western production, which increased from 1992 to 1999, showed a marginal decline in 2000. Over the past two years, low coal prices have led US coal producers to close uneconomic production capacity.

27. EIA (2001a).
28. Based on *WEO 2000* projections for OECD North America.
29. This US Energy Information Administration projects of coking-coal exports in 2020 equal to 34 million tons.

Despite recent production weakness, the US coal industry remains capable of meeting domestic and international demand in the future. The US is the world's second-largest coal producer. Mine productivity continues to surge. Since 1979, productivity has improved, on average, by 6.7% per year, the result of advanced technology, economies of scale and better mine design and management.[30] Improvements will continue in the future, maintaining coal's price advantage as a power-generating fuel.

India

Market Overview

India's energy sector is heavily dependent on coal. Coal accounted for over 75% of demand in the Indian power-generation sector in 1999. Although coal's growth is slower than that of other fuels and its share is expected to decline over the next 20 years, it will remain the largest contributor to Indian energy demand in 2020. Coal demand is projected to be some 756 million tonnes in 2020, up 120% on 1997. The power-generation sector will account for most of the growth in coal demand.

India's coal sector has been distorted by subsidies. The state-owned company, Coal India Ltd, produces 87% of domestic coal. A further 10% is produced by a joint undertaking between the central government and the state of Andhra Pradesh. Current policy allows private mines only if they are "captive" operations which feed a power plant or factory, although the Integrated Coal Policy announced recently that it will end this restriction. The central government has proceeded cautiously with reforms in the coal sector and considers that full privatisation is unfeasible. A gradual expansion of private activity through greenfield projects has been allowed, and the government is in the process of deregulating coal distribution and some coal prices.

Reserves and Production Outlook

Proved reserves in India are estimated at 82.4 billion tonnes, of which three-quarters are in Bihar, Madhya Pradesh and West Bengal.[31] Indian coal is high in ash, low in sulphur and of low calorific value. Domestic coal needs washing to make it suitable for coke ovens. Productivity is low, with mechanisation limited largely to coal cutting. Loading is done mainly by hand. Average production costs, which are low by international standards,

30. EIA (2001a).
31. IEA (2001a).

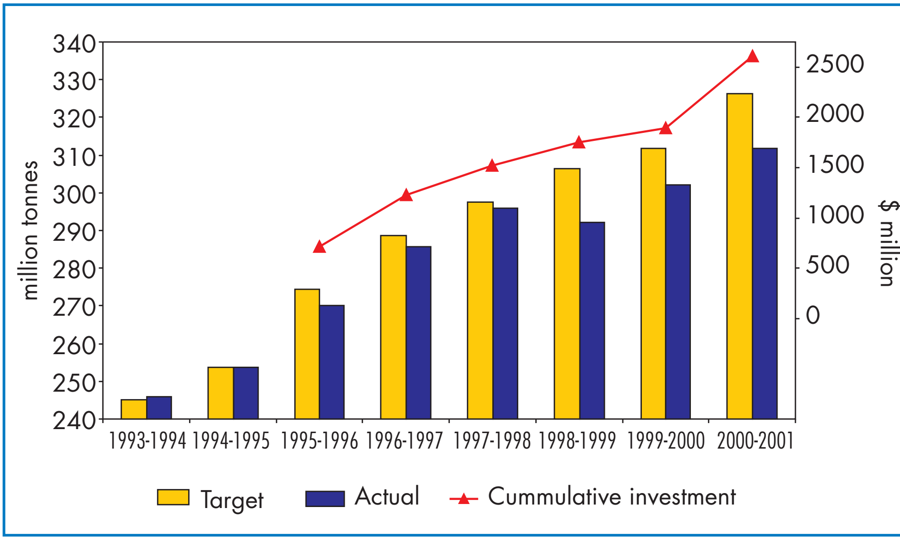
have been kept stable in real terms by lower costs in new developments. Most reserves lie far from major consuming centres. About three-quarters of coal production moves to power plants by rail, either on Indian Railways or on dedicated lines; the rest goes by truck or in coastal vessels. The lack of adequate port and rail infrastructure acts as a brake on both domestic and imported coal consumption. Rail transport is being modernised gradually, through electrification and higher-powered locomotives. Projected growth in coal consumption means that substantial investment in transport capacity will be required.

India is the world's third-largest coal producer, after China and the United States, and most of the country's coal demand is satisfied by domestic supplies. Production increased from about 73 million tonnes in 1971 to close to 300 million tonnes in 1999, and an estimated 309 million tonnes in 2000. While India's domestic coal production is not generally of export quality, some coal exports do go to Bangladesh and Nepal. The domestic coal industry is plagued by low productivity, low quality, distribution problems and loss of market share to higher-quality, less expensive imports. Because of the low quality of Indian coal, large amounts of coking coal must be imported, an estimated 15 million tonnes in 2000.

Although India's public coal companies maintained a pace of expansion through 1995 that allowed them to meet demand, their performance has slowed severely since then. The production shortfall occurred despite cumulative investment in the public companies of more than $2.6 billion over the last six years (Figure 4.15). Production problems have been especially acute for coking coal, which has fallen well below target for the past two years.

In recent years, India has been unable to raise the capital or develop the management skills needed to introduce mechanisation and achieve the economies attainable by advanced coal mining. Both the coal and electric-power sectors have failed to generate the cash margin needed to finance installation of the coal-washing facilities which are necessary for meeting environmental and coal-combustion standards. India's viability as a coal producer depends more on meeting investment needs than on the size of its proved coal reserve base. Investment prospects, in turn, depend on the implementation of reforms in the coal sector. Over the next two decades, Australia will probably remain the main Indian source for coking coal imports, while Indonesia, South Africa and China will probably provide more steam-coal imports. In order to meet the *WEO 2000* projected

Figure 4.15: **Targeted and Actual Production vs. Cumulative Investment**



Source: IEA analysis.

increase in steam coal demand, steam coal imports may need to expand from 9.1 million tonnes in 2000 to over 50 million tonnes by 2020.

Australia

Market Overview

Australia is the world's largest hard coal exporter. Less than 27% of hard coal production was consumed domestically in 2000. Australian demand for hard and brown coal in 2000 was 63.3 and 67.8 million tonnes, respectively. The bulk of coal demand is for power generation; coal-fired generation accounts for over 80% of total generation. Australia's domestic steel industry is the other primary consumer, but its demand has declined in relative terms as uneconomic steel mills have been closed.

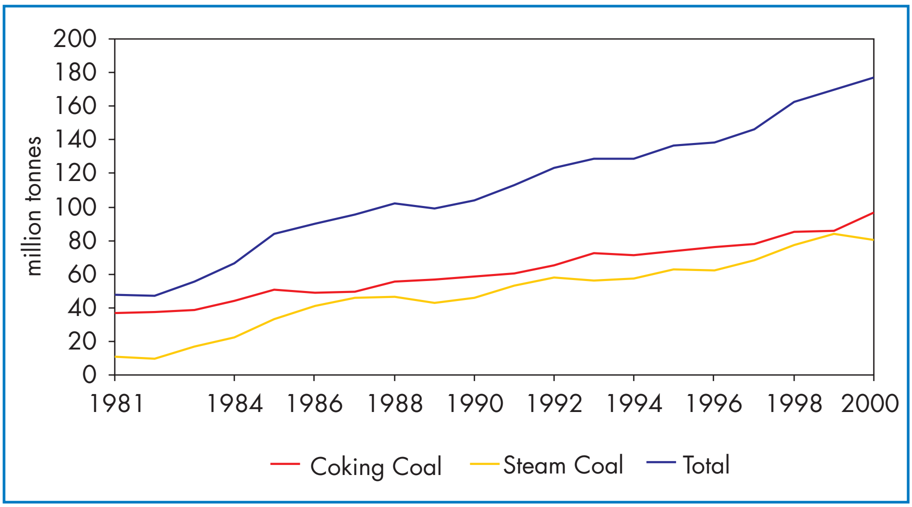
Australia's coal industry has undergone a process of consolidation over the past decade and now is relatively concentrated. Low coal prices in the late 1990s reduced profitability with some mines making losses. The industry responded by reducing costs and improving productivity, which has increased by some 20% per year over the last few years. The productivity growth is the result of more efficient work practices and investment in advanced mining technology to create more efficient mines.[32]

32. IEA (2001b).

Exports

Australia's coal mines are located close to major port facilities which have excellent seaborne transportation access to Asian markets. Efficient production and economies of scale also make Australian hard coal competitive in most other major international coal markets. Export growth was 8.2% per year in the 1980s, slowing to 5.5% in the 1990s. In 2000, coking coal exports were 97 million tonnes, and steam coal exports were over 80 million tonnes.

Figure 4.16: **Australia's Hard Coal Exports, 1981 to 2000**



Source: IEA.

The Australian Bureau of Agricultural and Resource Economics (ABARE) projects that Australia's share in the international coking coal market will rise from 49% in 1999 to 54% in 2010. This increase will be at the expense of other major exporters, primarily the United States and, to a lesser extent, Canada. Coking coal exports are projected to be nearly 120 million tonnes in 2020.

Australia is also expected to be the world's dominant supplier of steam coal, with exports of 143 million tonnes in 2020. Most of the growth in coal exports is expected to be directed to the Asian market, competition from emerging thermal coal suppliers such as China and Indonesia could cut into Australia's export performance. Some inroads into the European market are also possible.

Reserves and Production Outlook

Australia has proved hard-coal reserves of more than 42.5 billion tonnes. Queensland and New South Wales account for 90% of these reserves and for some 95% of total production. Total coal production in 2000 was 316 million tonnes, 76% hard coal. Australian hard coal is of high quality, with high calorific value, low sulphur and moderate ash content.

Based on proven reserves in New South Wales and Queensland, Australia has the potential to increase coal production capacity substantially. Some 28 million tonnes of additional capacity will be added by 2004.[33] Continuing a decade of productivity improvements in the mining industry, Australian coal producers are expected to increase their international competitiveness even further. The volume of proven coking and steam coal reserves will increase as coal transport and production infrastructure are extended in the Hunter Valley and Bowen Basin coalfields. Australia will remain a major supplier of coal for both domestic and international markets over the next two decades.

South Africa

Market Overview

South Africa is a major hard-coal producer and consumer, and the world's second-largest coal exporter. In 2000, coal demand was 154.5 million tonnes, a decrease of 1.3% from 1999. Electricity generation and the synthetic fuel industry account for roughly 78% of total consumption. South Africa has a highly developed synthetic-fuel industry and is the world's largest producer of coal-based synthetic liquid fuels. Most domestic hard-coal production is of thermal quality, although some domestic coking coal is produced. South Africa imported about 2 million tonnes of coking coal in 2000.

South African coal demand is expected to increase by 19%, to roughly 185 million tonnes in the next 20 years.[34] The increase will be stimulated by demand growth in the power generation sector.

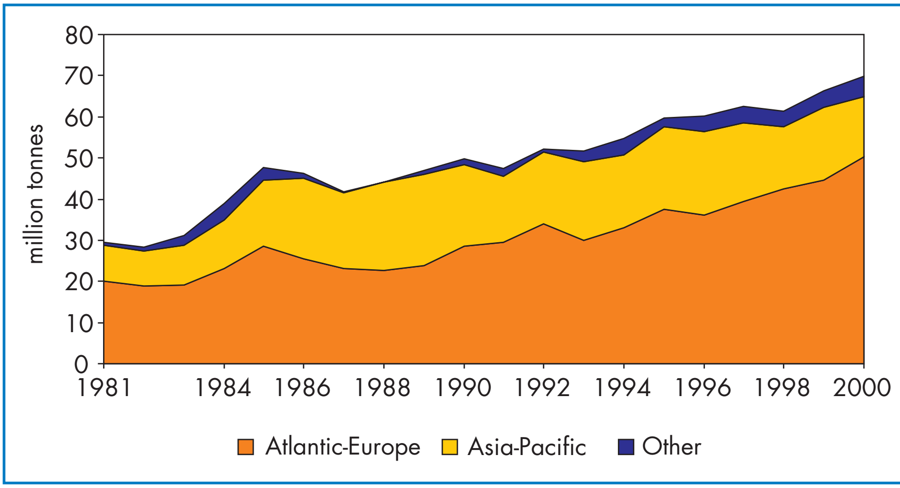
Exports

Coal exports, which amount to nearly one-third of South Africa's total production, rose from 66.2 million tonnes in 1999 to 69.9 million

33. Melanie et al. (2001).
34. Derived from regional projections in *WEO 2000*.

tonnes in 2000.[35] Exports, primarily of steam coal, increased nearly 5% annually over the past two decades. Because of South Africa's relative proximity to Europe, the Europe-Atlantic market has traditionally been the most important, accounting for about 70% of export demand (Figure 4.17). However, South African steam coal sells competitively in Asia-Pacific markets as well. South African coal acts as a price link between the two major steam coal markets.

Figure 4.17: **South Africa's Hard Coal Exports, 1981 to 2000**



Source: IEA.

Hard-coal export capacity is limited both by South Africa's inland rail transportation capacity and by loading and storage capacity at its major port of exit. The primary inland rail corridor, which handles 95% of coal exports, is the Richards Bay line, with a capacity of 72 million tonnes per year. The line is being upgraded to handle 82 million tonnes per year by 2003.

Based on the *WEO 2000,* South African exports are projected to reach some 124 million tonnes by 2020. Europe will remain the main market, but other African countries and India could increase their market share.

35. IEA (2001a).

Reserves and Production Outlook

South African hard-coal reserves were some 50 billion tonnes in 1999. Although South African export coal generally has a low calorific value and low volatile content, all export coal is washed to produce consistent ash and low sulphur levels. Coal production grew strongly in South Africa from 1993 to 1998 but stagnated when international coal prices fell in 1999. Since domestic demand growth was slow, and sales in the international market were unprofitable, production was cut back sharply in that year. It rose marginally to 225 million tonnes in 2000. Although infrastructure capacity is being expanded, future production will depend upon international coal prices and domestic demand.

The principal South African coalfields for export are the Witbank and Highveld. Mining in these fields will increasingly move from surface to underground, and the scale will likely rise as coal producers seek to remain competitive. These fields will have to be supplemented by new greenfield development — particularly in the Waterburg field — to increase production to meet expected domestic and international demand. These developments will require expansion of rail capacity in the existing system, plus construction of feeder lines to serve new collieries. Heavier reliance on the Waterburg field will increase the average distance that South African export coal must be hauled by 400 to 500 kilometres, which will add to supply costs.

Two factors will affect the rate of investment in South African coal reserves and infrastructure.

- The government is reviewing a new Minerals Development Bill, to open-up access to mineral resources. The intent is to open access to mineral resources and to discourage unproductive hoarding of mineral rights. The bill is being developed in discussions with stakeholders, but the process has introduced uncertainty for the large coal-producing companies that have traditionally controlled coal-reserve blocks. Proposals to dilute security and continuity of tenure could reduce the willingness of major coal producers to invest in South Africa until the mineral rights issue is settled.
- While the coal industry has typically been labour-intensive compared with other commercial coal-producing countries, there is a continuing shift to more mechanisation and larger scale mines. Tragically, this shift could be accelerated by the spread of AIDS, which has become epidemic in some coal-producing areas, and could curtail the supply of skilled labour.

There are no physical barriers to a large expansion of South African coal-production capability, if international and domestic coal prices support investment in unexploited coalfields and somewhat higher transportation costs. While uncertainties about labour and mineral control may retard expansion in the short term, strong demand and price signals will offset them, and ensure that South Africa plays a key role in coal production and international coal supply over the next two decades.

Russia

Market Overview

From 1988 to 2000, coal demand fell by nearly 38%, from 356 million tonnes to 246 million tonnes. Russian coal demand fell steadily from 1988 to 1998, but the trend reversed in 1999, and demand has increased in the last two years. While coal's share in total primary energy supply is expected to fall over the next two decades, total demand for coal is projected to increase by 1% a year until 2020. Over 70% of the incremental coal demand will come from power generation.

The Russian coal industry has been undergoing a major process of restructuring since 1993. Two phases of restructuring can be distinguished. The first phase, that of large-scale closures of uneconomic mines, raised the sector's competitiveness and labour productivity. The second phase, through which the Russian coal sector is currently struggling, is one of striving to improve existing and new fields so that they can compete in international coal and capital markets. The coal industry is hampered, however, by lack of cash, heavy social burdens, and the unstable investment climate in Russia. Meeting increasing domestic demand for coal will require Russia's coal industry to emerge strengthened from this second phase of restructuring.

Rising demand for coal is due partly to renewed economic growth and increasing electricity demand and partly to a new government effort to reduce Russian dependence on gas in the domestic fuel mix and increase the share of coal. The natural-gas monopoly, Gazprom, has put pressure on the government to reform its tariff structure and to realign the relative prices of gas and coal. One option that the government is considering is to increase the share of coal and to decrease the share of gas in electricity generation. Gas could then be redirected to export markets, which pay in hard currency, unlike domestic consumers who often pay late or not at all. Ultimately both domestic energy security and security for importers of

Russian coal and gas may depend on the creation of financially strong and stable coal suppliers.

Exports

Russian coal exports fell from more than 50 million tonnes per year in the late 1980s to 23.5 million tonnes in 1997. Exports have increased since 1998, and they exceeded 35 million tonnes in 2000. Increasing coal exports in the long term will require large investments in upgrading rail infrastructure and increasing the capacity of ports. If the government moves forward with plans to decrease domestic gas consumption, increased coal production will probably be targeted for the domestic market. In 2000, the proportion of hard coal exported was 20%, the highest per centage since 1992. Based on *WEO 2000*, Russian coal exports are projected to reach 38 million tonnes in 2020.

Reserves and Production Outlook

The World Energy Council estimates proven coal reserves in Russia at 157 billion tonnes. A major disadvantage is their poor location in relation to centres of population, industry and ports of exit. The proportion of Russian coal production from the western coalfields, where most recoverable coal is in thin, deep seams, has declined from more than 17% in 1990 to less than 7% in 1999, as restructuring has proceeded. Production is now concentrated in Siberia and, to a lesser extent, in Russia's Far East where coal is found in thick opencast mineable seams. Rail transport costs to the main ports and to consumers are high, and have been increasing due to the removal of subsidies and general inflation.

Production is expected to cover domestic coal demand from now to 2020. This could prove hard to achieve, however, given that coal production increased for the first time in over a decade in 1999. While the reserve base exists to support it, increased coal production will depend on infrastructure development, on attracting investment and on price reform. The Russian government intends to increase hard-coal and brown-coal production to between 340 and 430 million tonnes by 2020 (Box 4.3). Current capacity is estimated at about 275 million tonnes, so 25 million tonnes per year of new capacity is needed, in addition to replacement of exhausted capacity. Individual coal companies have announced new mines and expansion projects at existing mines that will provide some 25 million tonnes per year of additional hard-coal capacity by 2010 and nearly 36 million tonnes per year by 2020. The Russian government estimates the investment needs for the development of the coal industry over the next twenty years will be close to $20 billion.

Box 4.3: **Russian Energy Strategy Outlook for Coal Production**

Russia's official energy outlook, *Energy Outlook: Main Provisions to 2020*, foresees a decrease in the share of natural gas in favour of coal. The *Main Provisions* project an increase in coal production from about 260 million tonnes in 2000 to between 290 million tonnes and 335 million tonnes in 2010. By 2020, Russian coal production is projected to be between 340 and 430 million tonnes. Taking into account the retirement of depleted mines and the liquidation of loss-making companies with up to 60 million tonnes of capacity, the government estimates the need for new construction from 2001 to 2020 at some 200 million tonnes.

Indonesia

Market Overview

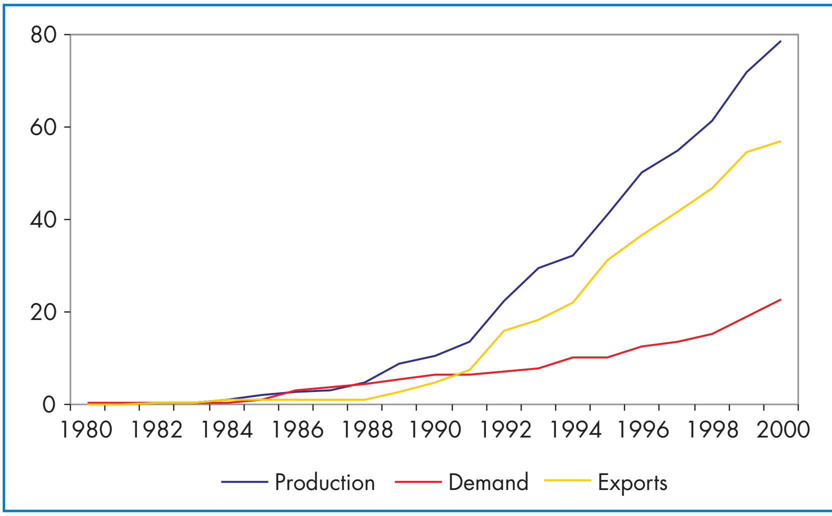
Indonesia is a large consumer and producer of coal. Production increased 9.2% in 2000 over 1999, from 72 million tonnes to 78.6 million tonnes. Coal demand increased over 21%, from 18.8 million tonnes to 22.8 million tonnes. Recent growth of coal demand is underpinned by strong expansion of coal-fired generation, which currently meets about a third of Indonesia's total electricity demand. The industry sector accounts for another 15% of coal demand, mostly for cement manufacture. There is also a large residential market for hard coal. Although Indonesia is a significant oil and natural gas producer, coal has gained desirability as a power-generation fuel so that oil and natural gas can be exported.

While coal production for domestic demand is growing in importance, export demand remains the driving force behind Indonesian coal production. In 2000, over 70% of production was exported.

Exports

Indonesia is the third-largest hard coal exporter after Australia and South Africa. Initial development of the hard coal sector was stimulated by

Figure 4.18: **Indonesia Coal Production, Demand and Exports**



Source: IEA.

the opening of large area surface mines, primarily located in Kalimantan. These mines were designed to produce coal destined for the international market. Although some injection-grade metallurgical coal is exported, the vast majority of Indonesia coal exports consist of low-sulphur steam coal. Exports increased from 1 million tonnes per year in the mid-1980s to nearly 57 million tonnes in 2000. Between 1985 and 1999, export growth averaged 29% annually, but it declined to 9.2% in 2000. Extremely low prices in key Asian markets discouraged Indonesian coal producers from expanding output. Production and exports were further dampened by labour problems, stiff competition from other producing countries, and disruption to the transportation infrastructure caused by flooding.

The Asia-Pacific market accounts for over 82% of export demand. In 1988, Indonesian coal exporters diversified their market base by exporting into the Europe-Atlantic market, which now accounts for 15% of export demand. The remaining export coal is shipped to markets in North and South America.

In 2000, over 94% of coal exports originated in Kalimantan. Coal transportation systems in Kalimantan range from sophisticated conveyance systems designed to maximise volume at low costs, to rudimentary crushing and sorting facilities, depending on manual labour and small truck haulage. A recently completed development project at North Pulau

Laut terminal made it capable of handling capesize vessels. Many smaller producers move coal directly to port, or to river terminals, where it is loaded into barges and loaded on seagoing vessels at Balikpapan.

Currently seagoing terminal capacity for Indonesia exceeds 75 million tonnes per year, which should cover domestic and export needs for the next few years. Based on an analysis of regional demand derived from *WEO 2000*, Indonesian hard coal exports are expected to reach nearly 105 million tonnes per year by 2020. To meet this expected hard coal export growth will require development of transport infrastructure, primarily a "hardening" of the roads, rivers and port infrastructure against weather-related disruption.

Reserves and Production Outlook

According to the WEC *Survey of Energy Resources 2001*, Indonesia possesses proven coal reserves of 5.4 billion tonnes, of which 790 million tonnes is hard coal. Currently, all coal production is classified as hard coal, although the country possesses significant reserves of sub-bituminous coal and lignite which could be used for domestic power generation. Since 1978, proven coal reserves have increased over 200% from 1.5 billion tonnes as the coal production and transportation infrastructure was extended. Hard coal reserves increased ten-fold from 70 million tonnes. At its current rate of hard coal production, Indonesia has proven reserves to sustain ten years of production. The country, however, has massive coal resources, and expansion of proven reserves is only a matter of stimulating more pre-mining exploration and planning.

Of Indonesia's domestic coal supply, over 38% originates in Sumatra, and 58% originates in Kalimantan. The vast majority of the coal is transported to Java, where most of the power generating and industrial markets are based. Export mines in Kalimantan are generally large area surface mines of up to 17 million tonne-per-year capacity. A small proportion of production comes from smaller-scale surface and underground mines. Future production expansion in Indonesia will occur at reserves capable of supporting large area surface mines.

Based on *WEO 2000* regional demand projections, Indonesian coal demand is expected to reach 35 million tonnes per year in 2020. While proven coal reserves pose no physical limitation to meeting expected growth in domestic demand and exports, the investment climate for coal producers and for coal-service providers is clouded by transportation constraints and political, social and economic upheaval. Coal production expansion has slowed in Indonesia, and will only resume when domestic stability is restored and when coal producers resume investment in production and transport infrastructure.

Latin America

Market Overview

The largest hard-coal producing and exporting countries in Latin America are Colombia and Venezuela. Total Latin American production in 2000 was 52.4 million tonnes. Of this, 37.1 million tonnes, or 71%, was produced by Colombia; and 8.9 million tonnes, or 17%, by Venezuela. Although they are major coal producers, Colombia and Venezuela consume only a modest amount of coal. Total coal demand in Colombia in 2000 was 3.8 million tonnes, down marginally from 1999. Some 29% of total coal consumed in Colombia is used to manufacture coke-oven coke, to raise steam and for pulverised injection in the iron and steel sector. Another 25% is used for cement manufacture. The power-generation sector accounts for most of the remainder. In Venezuela, coal demand in 2000 was just 491,000 tonnes, used primarily in the cement industry.

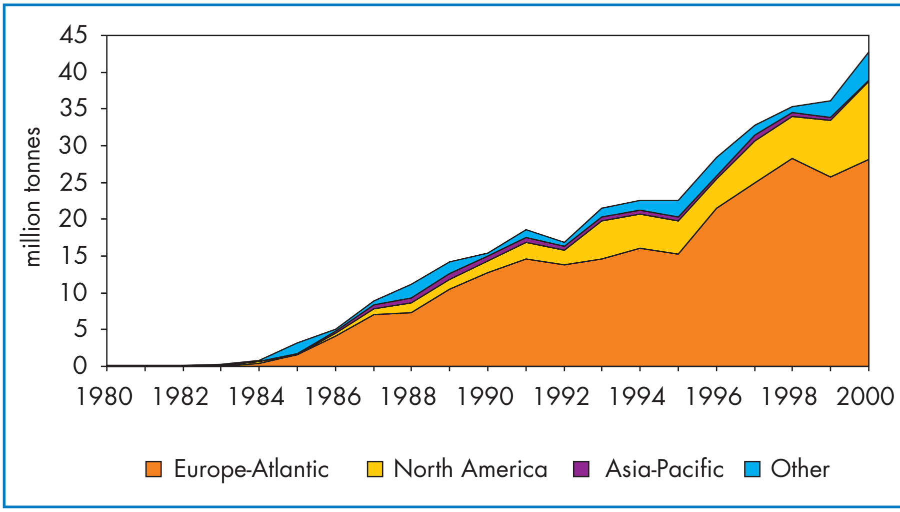
Although coal demand in both Colombia and Venezuela is expected to grow in the future, production will not be targeted for domestic consumption. Colombia is well endowed with hydro-electric resources for power generation, while Venezuela possesses extensive hydro, oil and gas resources. Coal production will be tailored, as it has since its inception, for the international coal market.

Exports

In 2000, coal exports from Colombia were 34.5 million tonnes and from Venezuela 8.2 million tonnes. Coal exports have grown very rapidly from both countries since 1980, primarily due to the development of large area surface mines which produce low-sulphur steam coal. From the start, these mines have supplied coal to the Europe-Atlantic market, in competition with South Africa and the US. Seaborne transport costs from Colombia and Venezuela are about one-half those from South Africa. Seaborne transportation rates from Latin America and the US to Europe are similar, but the cost of producing coal in Colombia and Venezuela is somewhat lower. Thus, in the 1980s and early 1990s, much of the

Colombian and Venezuelan production entered the Europe-Atlantic market. (Figure 4.19).

Figure 4.19: **Venezuela and Colombia's Hard Coal Exports, 1981 to 2000**



Source: IEA.

Beginning in the mid-1990s, new sulphur-emission restrictions were implemented in the US. Many plants in the eastern US with access to seaborne coal were able to acquire high-quality, low-sulphur coal from Latin America at a delivered cost much lower than the comparable US coal. The share of exports from Colombia and Venezuela to North America expanded from 10% of total exports in 1990 to 25% in 2000. Demand for Latin American coal in both the North American and Europe-Atlantic markets is projected to remain strong in the future.

The largest producing area in Colombia is served by a 145-kilometre standard-gauge railway which hauls coal to a shiploader at Puerto Bolivar. The dedicated port facility has a current capacity of 21 million tonnes per year. Production from the second-largest area is transported by rail 215 km to a captive port facility in Santa Marta. This facility has a current annual capacity of 12 million tonnes and is being expanded to 15 million tonnes.

Transportation logistics remain a major impediment to export development in Venezuela. Production from major sources in the Gusare coal basin must be trucked 80 to 90 kilometres, and then barged 13 kilometres to

Marcaibo for final loading. A new floating storage and transfer station, which was inaugurated in 1998, is designed to improve loading time and to raise total loading capacity. Currently the facility is rated at 7 million tonnes per year, but it will probably be able to handle at least half-a-million tonnes more per year. The government of Zulia State continues to promote a multi-commodity terminal. But with initial investment requirements in excess of $100 million, and total costs approaching $1.5 billion for a fully operative capesize port, financing remain a problem. Plans for this facility are likely to stay in limbo for some time.

Based on the *WEO 2000*, Colombian hard coal exports are projected to be over 72 million tonnes in 2020. Exports from Venezuela will be some 19 million tonnes. Strong demand in the power-generation sectors of the US and in OECD Europe will stimulate this demand growth.

Reserves and Production Outlook

According to the WEC *Survey of Energy Resources*, Colombia and Venezuela possess proven coal reserves of 6.6 and 0.5 billion tonnes respectively. Much of these reserves were added in the last twenty years, as coal production and transportation infrastructure was expanded to meet international hard-coal demand. Further expansion of coal production will undoubtedly open more proven reserves.

Coal production in Colombia resumed growth in 2000 after declining by nearly 6% in 1999. Output reached 37.1 million tonnes, 4.4 million tonnes higher than 1999. Over 94% of Colombia's total 2000 output was exported. In order to sustain domestic demand and export volume of this magnitude, investments in transport and port infrastructure are imperative. It is likely that additional steam-coal volume will be produced by operations in the Guajira and Cesar regions, which have enough coal reserves to sustain production of current magnitude well into the future. But the existing rail infrastructure and port facilities will need expansion to handle future coal volume.

Although coal has been mined in Venezuela for over thirty years, export-coal activity still centres on the western extremity of the country around the Guasare Coal Basin. The primary impediment to increased coal exports is inadequate internal transportation and port infrastructure. To acquire the $2 to $3 billion to reinforce this infrastructure, the international coal market will have to provide sustained returns to investors. Without the needed infrastructure development, coal producers will be reluctant to invest in additional capacity.

CHAPTER 5
GLOBAL RENEWABLE ENERGY SUPPLY OUTLOOK

Summary

The global renewable energy market will continue to grow

- Renewable energies include hydropower, bioenergy, wind, geothermal, solar, and ocean energy. The *WEO 2000* Reference Scenario projects that demand for renewable energy will grow by 2.3% per year over the next two decades. Demand for non-hydro renewables will increase faster than for any other source of energy, by 2.8% per year. Nonetheless, their share in the global energy mix will probably remain small in the absence of determined market intervention measures.
- In the OECD, most of the growth will be in the power sector, notably from increased use of wind and bioenergy. The share of non-hydro renewables in electricity generation increases from 2% in 1997 to 4% in 2020, under the Reference Scenario of the *WEO 2000*. The key factors underlying these expected trends are government policies and measures to curb greenhouse gas emissions, to diversify the energy mix and to enhance security of supply.
- The OECD Alternative Power Generation Case shows that if new policies and measures are introduced to support renewable energy, the projected share of non-hydro renewables in the OECD electricity generation mix could rise to nearly 9% in 2020.
- In developing countries, bioenergy will continue to play an important role in energy supply. Increased urbanisation and rising per-capita incomes, however, will cause the share of bioenergy in developing country energy demand to decline, from 24% now to 15% in 2020. Hydropower, an abundant indigenous resource in many of those countries will continue to expand, growing two-fold over the next twenty years.

Renewable energy resources are plentiful

- This study shows that renewable energy has the technical potential to meet large portions of the world's energy demand. Bioenergy has the technical potential to cover a much larger share of the world's energy needs in all sectors and applications: heat, power and transport. The world's supply of wind, solar and geothermal power can theoretically meet current global electricity demand many times over.
- Every region or country is endowed with renewable resources, but the potential varies among them. Sunny areas in the world have the greatest potential for solar energy use. Coastal areas, plains and offshore locations have the largest wind potential. Geothermal energy potential is abundant in areas with volcanic activity. Bioenergy is found in all countries with forests and a developed agricultural sector. Waste is available everywhere, and its quantities increase with population growth and urbanisation.
- Under current market conditions, the economic potential of renewables is much lower. Over the next twenty years economically recoverable resources will increase as a result of technological improvements that reduce costs and the economies resulting from expanding markets. New market valuations, however, (e.g., of carbon emissions) may be just as important. Factors that may limit supply are competing land uses and non-dispatchability.

Substantial benefits arise from increased use of renewables

- The most important benefits from using renewable energy sources are environmental protection and increased security of supply.
- Renewable energy is crucial in any strategy to fight global warming and will benefit as a market price is attached to carbon emissions.
- Renewable energy contributes to security of supply. The OECD's import dependence for gas and oil is set to rise over the next twenty years, and the issue of security of supply is expected to grow in importance. Renewable energy could play a key role in limiting import dependence.
- The *WEO 2000* Alternative Power-Generation Case showed that CO_2 emissions from the OECD power-generation sector could be reduced by 6% in 2020 compared to the Reference Scenario.

Developing renewable energy will require significant investment

- Developing renewable energy resources will require large investments in infrastructure. In the OECD, investment in bioenergy, wind, geothermal and solar projects is expected to be on the order of $90 billion over the next twenty years in the Reference Scenario of the *WEO 2000*. This amount of money represents 10% of total power sector investment over the next twenty years.

- Investment in renewables is much larger in the Alternative Power Generation Case. The higher share of renewables projected in the Alternative Case corresponds to some $228 billion or 23% of OECD investment in new power generation capacity over the next two decades.

Substantial cost reductions will be required

- Most forms of renewable energy are not competitive when their costs, as measured in today's markets, are compared with conventional energy sources. Natural gas-fired CCGT plants are currently the preferred option for new power-generation projects. Such plants will continue to be attractive as long as natural-gas prices remain low. In many developing countries, China and India in particular, coal is an abundant indigenous resource and the most economic option for power generation.
- The costs of renewable energy technologies have already fallen but further reductions are needed for renewables to compete with the least costly fossil-fuel alternatives. The rate at which costs will decline in the future is uncertain.
- Under moderate fossil-fuel price evolution and assuming no major government policy changes, few renewable energy sources will be able to compete with fossil fuels. Renewable energy can be cost effective in specific applications. Some technologies, such as wind, are close to being competitive, while others need to see dramatic declines in their costs. In any case, renewables have to compete with many non-renewable energy forms whose costs are also likely to decline.
- Costs are highly site specific and the best sites are used first. Costs for marginal sites are generally much higher.

Government support will be necessary

- Increasing the share of renewable energy sources in the energy mix of OECD countries will require continuous and large government support.
- Two major recent developments are likely to result in increased government support for renewable energy. These are the agreement on climate change in Bonn, which makes the ratification of the

Kyoto Protocol more probable, and the adoption of the Renewable Electricity Directive by the European Parliament.

- Research and development (R&D) support has played an important role in the emergence of renewables. Maintaining this support could help accelerate the development of renewable energy.
- Strong support at the early phase of development can lower the cost of renewable technologies. As renewables gain market share, government involvement could be reduced.
- A gradual reduction in government subsidies over time will also be necessary to minimise the impact on consumer prices.

Bioenergy

- The use of bioenergy in combined heat and power applications, where markets for heat exist, can be cost-effective in some cases. Co-firing may be a low-cost option for existing coal power plants, especially for low-cost sources of bioenergy such as waste derived fuels. Bioenergy for heat applications may be cost-effective in some OECD countries, especially where wood resources are available. On average, however, the development of bioenergy projects for electricity production will remain fairly costly.
- Biofuels currently account for only a small portion of global transport fuels. In most countries, they are only competitive if they enjoy government subsidies. Technological advances in the production of biofuels, for example the use of woody bioenergy instead of agricultural crops, could reduce costs and increase renewables' market share in the longer term.
- Bioenergy will continue to be a major energy source in developing countries over the next two decades. The level of demand for bioenergy will increase by nearly 25% in these countries, but its share in total primary consumption will fall.
- The share of bioenergy in residential energy demand in some developing countries is greater than 90%. Improving the efficiency of its use can lead to important savings in fuelwood consumption and can prevent the rapid decline in forested areas.
- Availability and costs will remain key factors in bioenergy development. Competition from agricultural uses, the seasonality in bioenergy crop production and the distances from bioenergy sources and energy use are major factors influencing cost.

- The use of bioenergy can have many environmental benefits over fossil fuels if the resource is produced and used in a sustainable way. Environmental issues, regarding airborne emissions from solid bioenergy combustion will, however, increase in importance along with the use of this fuel. This is particularly important for waste incineration, which faces public opposition, and siting new facilities may be difficult.

Hydropower

- Global electricity production from hydroelectricity plants will increase by 1.8% a year over the next twenty years.
- Developing countries will account for 80% of the projected increase in hydroelectricity, three-quarters of it in China and Latin America.
- The development of large-scale hydropower may have negative environmental and socio-economic effects, which could restrain growth. Small hydro systems have modest and localised effects on the environment.
- The development of new hydro projects over the next twenty years could be cost-effective in many cases, particularly in developing countries.

Geothermal

- Geothermal energy use will almost triple over the next twenty years. Its growth will be limited by the availability of sites, which are often far from demand centres.
- Cost reductions in exploration and drilling and in geothermal conversion systems will be necessary to improve the competitiveness of geothermal energy.

Wind Power

- Wind power is the most rapidly growing renewable energy source. Demand for it is expected to increase by nearly 13% a year over the next twenty years.
- The cost of producing electricity from wind power is high compared with fossil fuels, but declining capital costs and improved performance are likely to reduce generating costs. Wind is expected to be competitive with fossil-fuel-based generation on the best sites on land over the next decade.
- Large land requirements and competition among different land uses could constrain growth. The intermittence of wind power and

the unsightliness of wind turbines could further limit site availability.

- The effects of intermittence must be taken into consideration at the early stages of wind power development, as the effects may become more obvious with higher shares of wind in the electricity mix. Integrating wind into power networks could raise costs if reserve margins need to be larger.
- Strong cost reductions will be required for offshore wind farms to be competitive. Offshore wind power is not expected to be a cost-effective option over the next twenty years.

Solar

- Substantial reductions in capital costs will be necessary for solar power technologies to compete with the least-cost fossil-fuel options.
- Steady growth in solar power continues, but its share in total generation remains low because of the high costs involved.
- Most future growth in solar power will be in photovoltaics (PV) for building applications.
- PVs are used and will continue to be used in rural electrification projects. They are an effective way to serve the substantial rural populations who do not otherwise have access to basic energy services.
- Utility-scale development of solar technologies is unlikely to take place on a large scale over the next twenty years. The high cost of these technologies will limit their ability to penetrate the market.

Overview of Renewable Energy Trends

Renewable energy[1] accounted for 5% of the world's total primary energy supply (TPES) in 1999. Over the next two decades, renewable energy is projected to increase at an average annual rate of 2.3%. The *WEO 2000* projections of renewable energy are summarised in Table 5.1.[2]

Non-hydro renewable energy is expected to increase more rapidly, at 2.8% per year, and faster than any other energy source. Bioenergy, wind, solar and geothermal are expected to contribute increasingly to the global

1. Bioenergy (excluding developing countries), hydropower, geothermal, wind, and solar energy.
2. The *WEO 2000* projections use 1997 as the base year. IEA energy data are available up to 1999 and are used in the text where possible.

Table 5.1: **Total Primary Energy Supply of Renewable Energy by Region**
(Mtoe)

	1997	2020
World	**410**	**697**
OECD	**286**	**434**
Europe	106	190
North America	150	191
Pacific	30	53
Transition Economies	**23**	**32**
Developing Countries	**101**	**231**
China	17	56
East Asia	15	49
South Asia	9	20
Latin America	53	91
Middle East	2	4
Africa	6	11

Note: Figures do not include bioenergy in developing countries.
Source: IEA (2000).

energy mix. Most of the projected growth will be in the power sector in OECD countries.

If non-commercial bioenergy in developing countries is included, the current share of renewables in TPES is 14%. However, urbanisation and rising per capita incomes will tend to reduce bioenergy use in these countries. Consequently, the share of *all* renewable energy, including bioenergy in developing countries, in world energy demand will fall to 12% in 2020.

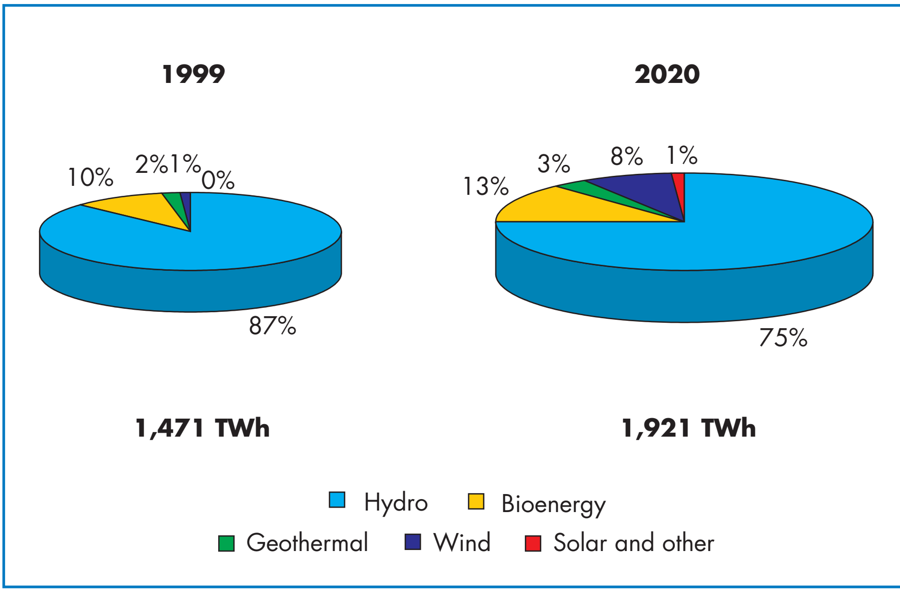
OECD Countries

In OECD countries, renewable energy has been receiving increasing attention because of its environmental benefits and because it contributes to security of supply. Total renewable energy accounted for 6.3% of TPES in the OECD in 1999. This share is projected to rise to 7.4% by 2020.

Renewable energy in the OECD is mostly used for electricity production. In 1999, the power sector consumed two-thirds of total renewable energy. The remainder, mostly in the form of bioenergy, was used for heat production in the industrial and residential sectors. Current consumption of biofuels in the transport sector is negligible. The contribution of biofuels to the transport fuel mix is expected to remain limited over the next twenty years.

Electricity generation from renewable-energy sources accounted for 17% of total electricity in 1999. As Figure 5.1 indicates, hydropower is by far the largest source of renewable electricity in OECD countries, accounting for 14% of OECD total electricity generation and 87% of its renewable electricity in 1999. Bioenergy is the second largest source, with a 10% share in renewable electricity in 1999.

Figure 5.1: **OECD Renewable Electricity Generation, 1999 and 2020**



Source: IEA data and IEA (2000).

The Reference Scenario of the *World Energy Outlook 2000* takes into account government policies and measures enacted up to mid-2000. Because support for renewables may be stronger in the future, an Alternative Power Generation Case was developed for the OECD regions. This case assumes that policies to promote renewables are strengthened and augmented, resulting in a higher share of renewables in the OECD electricity mix. Hydropower was not included in the Alternative Case. In the future, growth in hydropower in OECD countries is expected to be limited because many of the best hydro-electric sites have already been exploited, and because environmental concerns limit development. Table 5.2 compares the results of the Reference Scenario with the Alternative Case.

Table 5.2: **OECD Alternative Power Generation Case**

	% Share of Renewables in 2020		**% of Power Sector Investment 1997-2020**	
	Reference	Alternative	Reference	Alternative
North America	3	8.1	7	28
Europe	5.2	10	13	24
Pacific	4.1	6.4	9	16
OECD	**4**	**8.6**	**10**	**23**

Source: IEA (2000).

Non-OECD Countries

Outside the OECD, use of renewable energy will continue to rise in developing countries. In the transition economies — the former Soviet Union and Central and Eastern Europe — growth in renewable energy is likely to be very small.

Hydropower will continue to be an important source of electricity generation in many developing countries. Such generation could more than double over the period 1997-2020. Its share in the electricity generation mix, however, is expected to fall by two percentage points by 2020. Other renewable-energy sources, notably geothermal, wind and solar, are also expected to be exploited more widely, but their contribution will remain limited.

Bioenergy in Developing Countries

Bioenergy use in total final consumption (TFC) is expected to go on increasing in developing countries over the next twenty years, but the rate of increase will slow down considerably. Bioenergy energy use in developing countries will grow more slowly for several reasons. Bioenergy is projected to be used in a more efficient and sustainable way. Higher per capita incomes and increased urbanisation will promote substitution towards fossil fuels. The main use of bioenergy in developing countries is firewood for cooking, supplies of which are already becoming scarce.

Costs and Benefits from Increased Use of Renewables

Renewable energy is, in most cases, an expensive form of energy compared with fossil-fuel alternatives.[3] Currently, renewable development in OECD countries is dependent on various support programmes. Table 5.3 shows electricity generating costs for various power generation alternatives for European Union countries.

Table 5.3: **Electricity Generating Costs for Various Alternatives**

Euro cents/kWh (1990 values)	Coal*	Gas Combined Cycle	Bioenergy	Wind	Solar PV	Nuclear
Austria	3.6	3.4	3.6	7.2	64.0	5.9
Belgium	3.2	2.8	3.7	7.2	64.0	4.0
Denmark	3.6	2.9	3.9	6.7	85.3	5.9
Finland	3.2	2.6	3.9	7.2	85.3	3.8
France	3.2	3.2	4.0	7.2	51.2	3.4
Germany	3.2	3.5	4.3	6.8	64.0	5.1
Greece	3.5	3.5	4.0	7.2	51.2	4.6
Ireland	3.2	3.2	4.5	7.2	85.3	4.7
Italy	3.2	3.4	4.0	7.2	51.2	5.0
The Netherlands	3.6	2.6	4.0	7.2	64.0	5.1
Portugal	3.2	3.4	4.3	7.2	51.2	5.9
Spain	3.6	3.5	4.3	7.1	51.2	4.7
Sweden	3.6	3.3	3.4	7.2	85.3	4.7
United Kingdom	3.2	2.6	3.8	7.2	64.0	4.3

* Pressurised Fluidised Bed Combustion.
Note: Production costs are for power generation at 7,000 hours and exclude excise taxes and subsidies.
Source: Commission of the European Communities (2000).

3. A forthcoming IEA publication will analyse the cost of renewable energy.

Growth in renewable energy in OECD countries over the next twenty years will rely on the continuation of government intervention. Although the cost of renewable energy is expected to fall in the future, the rate of decline is uncertain. The Reference Scenario of the *WEO 2000* shows renewable energy remaining a comparatively costly option over the coming two decades, if the cost of energy is measured in today's markets. The competitive position of renewable energy *vis-à-vis* fossil fuels would improve substantially if a market price were attached to carbon dioxide emissions.

Wind power could be in close competition with fossil fuels within the next decade in locations with very good wind conditions and under the assumption that current capital costs are reduced. Similarly, bioenergy could be cost effective in CHP applications if the cost of fuel is low. Table 5.4 gives a qualitative assessment of the current costs and a range of likely reductions by 2020. The estimates shown here are average and can vary significantly depending on site conditions.

Table 5.4: **Renewable Electricity Cost Assessment**

	Current Cost	**Cost Reductions by 2020**
Bioenergy	High. Cost-effective in CHP applications with low fuel cost. Co-firing is a relatively low cost retrofit option.	10%-15%
Wind onshore	Relatively low for onshore, lowest compared to other renewables.	Up to 15-25%
Wind offshore	High.	20- 30%
Solar PV	Very high. Cost-effective only in niche markets.	30%-50%
Solar Thermal	Very high.	30%+
Geothermal	High.	10%
Hydro	Relatively low for large hydro. Higher for mini-hydro.	10%

Source: IEA analysis.

The most important benefit from increased use of renewable energy is emission reductions, particularly of greenhouse gases. Renewable energy produces no CO_2 emissions (or very low emissions compared with fossil fuels on a full-cycle basis). The Alternative Power Generation Case in the *WEO 2000* estimates CO_2 emission reductions for the three OECD regions in the event that more renewable energy is substituted for fossil fuels.

Table 5.5: **Power Sector CO_2 Emission Reductions in 2020 in the Alternative Case**

	Reference (million tonnes)	**Alternative** (million tonnes)	**% Reduction**
North America	3,127	2,950	5.7
Europe	1,680	1,567	6.8
Pacific	665	640	3.8
OECD	**5,473**	**5,157**	**5.8**

Note: Non-hydro renewables only.
Source: IEA (2000).

Renewable energy also contributes to security of supply and energy diversification. OECD oil and gas import dependence are set to rise over the next twenty years and therefore the issue of security of supply is expected to grow in importance. Renewable energy could have a key role in securing energy supplies. Its role in fuel diversification can be significant, particularly in the power sector. Table 5.6 shows the coal and gas savings achieved in 2020 in the Alternative Power Generation Case compared with the Reference Scenario.

Table 5.6: **Power Sector Fuel Savings in 2020 in the Alternative Case**

	Coal		**Gas**	
	Mtoe	% Reduction	Mtoe	% Reduction
North America	32	5	21	8
Europe	12	5	28	10
Pacific	4	4	3	4
OECD	**48**	**5**	**53**	**8**

Source: IEA (2000).

Key Factors Affecting Renewable Energy Supply Prospects

Bioenergy Supply Prospects

Bioenergy Resources

Bioenergy can be derived from a wide range of materials of different origin and with different properties. The most important bioenergy fuels are forest products, agricultural residues and wastes, energy crops, and municipal solid waste (MSW).

The International Institute for Applied Systems Analysis (IIASA) has produced a scenario of global bioenergy potential by world region, based on economic criteria.[4] The scenario assumes that the cost of bioenergy is reduced in the future because of progress in increasing yields per unit of land and in improving the conversion efficiency of bioenergy combustion. Table 5.7 shows the potential for 1990 (the base year) and a range of estimates for 2020.

Table 5.7: **World Bioenergy Potential** (Mtoe)

	1990	2020
Crop residues	420	482-499
Wood	1,483	1,791-2,025
Energy crops	2,689	2,971-3,535
Animal waste	688	994
Municipal waste	112	516
Total	**5,393**	**6,755-7,569**

Source: Fischer and Schrattenholzer (2001).
Note: Original data in EJ (exajoules). 1 EJ=23.8846 Mtoe.

The total economic potential in 1990 was 5.4 Gtoe with actual consumption about five times less. Under this scenario, the bioenergy potential in 2020 could increase by 25% to 40%.

4. Fischer and Schrattenholzer (2001).

Technology

Today, most bioenergy applications use direct-fired technology. Solid bioenergy is burned in a process similar to burning coal but with lower efficiencies, typically ranging from 15% to 30%. With cogeneration of heat and electricity, total efficiency is on the order of 60%.

Bioenergy in gaseous state can be burned in gas turbines (open or combined cycle) and in internal combustion engines. Most of it is landfill gas, a low- to medium-calorific value gas that is produced from MSW. The utilisation of landfill gas requires the development of a recovery system with wells or trenches to collect the gas.

Co-firing is the practice of using bioenergy as a supplementary energy source. Bioenergy can be burned along with another fuel, typically coal, but such a process requires modifications or additions to the power plant. Co-firing is a retrofit option for existing coal plants to achieve a large scale introduction of bioenergy in the power sector. Direct addition of solid bioenergy limits the amount of solid bioenergy that can be burned with coal to about 10% to 15%. Solid bioenergy can be gasified and the gas co-fired with coal or with natural gas. If solid bioenergy is gasified prior to co-firing, the percentage that can be added is higher as compared to direct use of solids.

Advanced bioenergy technologies include gasification and pyrolysis. Advanced technologies can achieve high conversion efficiencies. Bioenergy gasification technology converts solid bioenergy into a combustible gas through a partial oxidation process. The resulting gas can be of low or medium calorific content depending on the conditions of the gasification. This gas can be burned in a turbine, a fuel cell or an internal combustion engine. Gasification technology is at an early stage of commercialisation with some companies already offering gasification units for direct co-firing applications.

In pyrolysis, the fuel is heated in the absence of air to produce gas, oil and char. Fast pyrolysis techniques produce a higher proportion of the oil while slow pyrolysis makes char. The technology is moving from the R&D to the commercialisation phase.

Supply Costs

The cost of producing electricity from bioenergy depends on the technology, the fuel cost and the quality of the fuel. Most bioenergy used for electricity production is in solid state. Bioenergy power plants tend to be small in size. A typical plant size is 20 MWe or less.[5] Bioenergy plants, therefore, have higher capital costs per unit of installed capacity and higher operating costs per unit of electricity produced than fossil-fuel plants. Table 5.8 shows recent capital cost estimates for bioenergy power plants.

Table 5.8: **Capital Costs for Bioenergy Technologies**

Country	Capital Cost ($/kWe)	Plant Type	Source
US	1,965 2,102 272	Direct combustion Gasification Co-firing (retrofit)	EPRI and US DOE (1997)
US	800-1,500 800-1,000 700-900 600-800	CHP reciprocating engine, biogas CHP steam turbine, all fuels CHP combustion turbine, biogas CHP combined cycle, biogas	EIA (2000)
Germany	4,632-7,629	CHP, wood (90% heat, 10% electricity on a MW basis)	Nitsch, J. *et al.* (2000)
Denmark	2,719-3,708 2,101-3,214	CHP steam turbine (wood chips, straw) Gasification (wood chips)	Centre for Biomass Technology, Denmark

Bioenergy fuel costs vary widely (Table 5.9). The fuel cost can be zero in certain cases, especially if it is a byproduct. Most estimates are in the range of $150 to $250 per toe. The bioenergy fuel source must be abundant, reliable and low-cost. Factors that affect the cost of bioenergy supply are competition with other uses, variation in crops and seasonality, and distance from the source.

The electricity-generating costs of bioenergy are, on average, higher than those of fossil-fuel plants because of their higher capital costs, higher fuel costs and lower conversion efficiencies than conventional plants.

5. IEA GREENTIE (www.greentie.org).

Table 5.9: **Bioenergy Fuel Cost Estimates**

Country	**Fuel**	**Cost** ($/toe)	**Data Source**
Denmark	Straw	141	Centre for Biomass Technology, Denmark
	Wood chips	166-176	
	Wood pellets	190	
Austria	Wood chips	163	CLIP (1998)
Finland	Wood chips	142	CLIP (1998)
France	Wood chips	186	CLIP (1998)
Sweden	Wood chips	151	CLIP (1998)
Netherlands	Residues	35-182	BioMaster (NOVEM)*
	Imports	66-172	
	Energy crops	137-263	
Germany	Wood	0-261	Nitsch, J. et al. (2000)
	Straw	0-410	

* Converted from original data assuming a calorific value of 20 GJ/tonne.

Environmental Issues

The use of bioenergy can have many environmental benefits over fossil fuels if the resource is produced and used in a sustainable way. If the land from which bioenergy is produced is replanted, bioenergy is used sustainably and the carbon released will be recycled into the next generation of growing plants. Substituting fossil fuels with bioenergy means the carbon from the displaced fossil fuels remains in the ground and is not discharged into the atmosphere. The extent to which bioenergy can displace net emissions of CO_2 will depend on the efficiency with which it can be produced and used.

Bioenergy plants have lower emissions of SO_2 than do coal and oil plants. They may produce, however, more particulate matter than oil- and gas-fired plants. These emissions are in generally controllable but they increase generating costs.

Overview

In 1999, global electricity generation from bioenergy was 160 TWh, a little more than 1% of the total. Nearly all of it was in OECD countries, where

Table 5.10: **Bioenergy Electricity Production in 1999**

Country	Bioenergy Electricity (TWh)	% of Total Electricity
US	63.5	1.6
Japan	16.2	1.5
Germany	9.4	1.7
Finland	8.7	12.5
Brazil	8.5	2.6
UK	7.7	2.1
Canada	7.1	1.2
Netherlands	4.0	4.6
Australia	3.7	1.8
Sweden	3.4	2.2

Source: IEA data.

it accounted for 1.6% of total generation. Table 5.10 shows the ten countries with the highest levels of bioenergy electricity production in the world.

More than half of bioenergy electricity is produced from solid products, such as forest products and agricultural residues. Waste accounted for 35% of total bioenergy electricity production and its share has been increasing. Waste incineration is used to provide energy in several countries.

Prospects

Bioenergy is a well established option for electricity and heat production and this is likely to continue in the future. Electricity generation from bioenergy is expected to double over the next two decades. Most of the increase is likely to be in OECD countries, where the share of bioenergy in electricity generation rises from 1.6% in 1997 to 2.1% in 2020. Bioenergy is likely to remain, on average, a fairly expensive option compared with fossil fuels. However, where there is demand for heat and where bioenergy fuels are available at low or no cost, using bioenergy in CHP may be economical. Declines in generating costs are likely to occur over the next twenty years because of reductions in the capital costs of bioenergy plants and efficiency improvements. The evolution of the fuel-price component is more uncertain. Wider use of energy crops is likely to increase costs.

Transportation

Biofuels are liquid fuels produced from bioenergy feedstocks through a number of chemical processes. The two biofuels that are the most advanced are biodiesel and bioethanol. Most biodiesel is processed from oilseed rape and sunflower oil. Bioethanol is processed from wheat, sugar beet and sweet sorghum. World ethanol production in 1998 was 60% from sugar crops, 7% synthetic and 33% from other sources.[6]

Overview

Brazil and the United States have the largest programmes promoting biofuels in the world. Brazil, one of the world's largest producers of sugarcane, successfully implemented a subsidised ProAlcool programme. The programme was aimed at decreasing dependence on imported oil for energy, and farmers were given financial incentives to switch from sugar to alcohol production. In 1985, pure-ethanol car sales represented 96% of the market, and, by the end of the 1990s, 4.5 million such vehicles had been sold.[7]

By 1997, low international oil prices and the gradual elimination of subsidies for alcohol cars reduced the profitability of ethanol production, and the sales of pure ethanol cars dropped almost to zero. On 1 November 1999, all price subsidies for ethanol were eliminated. Ethanol producers' prices increased 216% from May through November 1999, according to the Brazilian Finance Ministry. Ethanol consumer prices rose 73% over the same period.[8] Today, one-quarter of the vehicle fleet in Brazil consumes pure ethanol. The remainder of the fleet consumes a blend of gasoline containing up to 24% ethanol by volume.[9]

Fuel ethanol produced from corn has been used in gasohol or oxygenated fuel in the US since the early 1980s. These gasoline fuels contain ethanol at concentrations of up to 10% by volume. Ethanol demand in the United States is estimated to be 1.3 billion gallons,[10] or roughly 1% of total US gasoline consumption. Gasohol, a mixture of 10% ethanol and 90% gasoline, is widely used in parts of the Midwest and South. Ethanol production from corn in the US receives a federal tax subsidy. Prospects for lowering costs and expanding ethanol production

6. Berg (1999).
7. Moreira and Goldemberg.
8. Country information for Brazil (www.embassy.org).
9. Trindade (2000).
10. Urbanchuk (2000).

are limited, because of the high level of inputs, such as fertiliser, pesticides and tractor fuel.[11]

In the European Union, biofuels accounted for 0.15% of transport fuels in 1998. France and Italy account for more than two-thirds of the current biodiesel and bioethanol market in the EU. France uses wheat and sugar beets for feedstocks. The farmers are paid to switch production from food crops. Biodiesel could be used more easily on a larger scale because it can be used for heating and for transportation and does not require changes in the distribution network.

Table 5.11: **Cost of Producing Bioethanol from Various Feedstocks**

Crop	**$ per cubic metre**
Sugar beet (at 15 Euros per tonne)	300 – 400
Sugar cane	260
Sweet sorghum	200 – 300
Corn (at $120 per tonne)	300 – 420
Wheat (at $140 per tonne)	770
Lignocellulosics (enzymatic hydrolysis)	180

Source: Grassi (2000).

Choice of feedstock for biofuels is important, because the delivered cost of the raw material accounts for 60% to 80% of the cost of production.[12] Table 5.11 shows bioethanol production cost data for various feedstocks.

Environmental Issues

Using biofuels in motor vehicles helps reduce GHG emissions. Full-cycle analysis indicates that, on average, biofuels emit less CO_2 than conventional fuels. The reductions depend on the biofuel and its use. Advances in biofuel production and combustion technologies will improve further the environmental performance of biofuels.

11. Natural Resources Defence Council (www.nrdc.org).
12. Trindade (2000).

Prospects

Over the next twenty years, the share of biofuels in transport energy demand is expected to remain limited. Biofuels do not, in general, compete with gasoline and diesel on a cost basis. Competing land uses may limit supply. The main cost element in biofuel production is the feedstock, so research currently concentrates on the identification of cheaper feedstocks to reduce the costs of fuel production and help make it more competitive with fossil fuels.

Residential and Industrial Applications

Industrial bioenergy includes the use of sawdust and bark in the wood industries, bagasse in the sugarcane processing sector, and black liquor in the kraft pulping industries. The pulp and paper industry is the most important user of bioenergy for heat production of all industrial branches. It accounted for about half of industrial bioenergy energy demand in the OECD in 1999. In developing countries, bioenergy is the main source of energy for many small industries, including baking, brewing, textile manufacture, brick-making and fish-smoking. In Asia, rural industries account for some 20% of the region's fuelwood consumption.[13] The steel industry in Brazil is the world's largest user of charcoal.

Bioenergy is used for district heating in some countries, notably in Europe. France, Sweden, Denmark, Finland and Austria are the largest users. In these countries, bioenergy is used in centralised systems to deliver heat to final users through dedicated networks.

In the residential, commercial and public sectors, bioenergy provides heating, cooking and lighting services. Residential heating is the largest market for bioenergy use for energy in Europe, accounting for 44% of total bioenergy consumption in OECD Europe in 1999. The main traditional use of bioenergy in developing countries is as firewood for cooking. Fuelwood provides some 20% of rural household consumption in Latin America and about 50% in Africa.[14] It accounts for 11% of energy consumption in China, 30% in India and over 80% in Bhutan, Cambodia, Laos and Myanmar.[15]

13. Regional Wood Energy Development Programme in Asia (www.rwedp.org).
14. Foundation for Alternative Energy, Slovakia, (www.fns.uniba.sk).
15. Regional Wood Energy Development Programme in Asia (www.rwedp.org).

Bioenergy in Developing Countries

In developing countries, bioenergy is often consumed without regard to the effect of its use on the environment. Bioenergy will continue to dominate energy consumption in many developing countries over the next twenty years, the challenge for policymakers being to promote its more sustainable and efficient use. Increasing the efficiency of bioenergy use can be achieved by improving current technologies, by introducing new or more advanced bioenergy technologies, and by using plantations to supply sustainable bioenergy crops.

Technology

Improved Cookstoves

In developing countries, some 80% of bioenergy use is for cooking. Traditional bioenergy cooking techniques in many developing countries are inefficient. Advanced bioenergy cookstoves improve efficiency considerably. They also improve health in rural areas, where illnesses attributed to indoor smoke are very common.[16] There is extensive scope for introducing improved cookstoves, since only very few developing country households currently have them.

Nearly 800,000 improved stoves were distributed in Kenya and over 30,000 in Rwanda in the 1990s.[17] The improved stoves were some 35% to 40% more efficient than traditional cookstoves. An estimated 363 ktoe was saved annually in Kenya.[18] The savings in household income were some 20% of average annual incomes of $350.

Table 5.12: **Savings from Improved Stoves in Africa**

	Average daily charcoal consumption (kg per person per day)		**Yearly savings per family** (kg)	**Value of savings** ($)
	Traditional Stove	Improved Stove		
Kenya	0.67	0.39	613	64.70
Rwanda	0.51	0.33	394	84.10

Source: Karekezi and Ranja (1997).

16. See, for example, Kammen (2000) and World Bank Group (2000).
17. Karekezi and Ranja (1997). In the mid-1990s, improved charcoal cookstoves in Africa cost about $8 while traditional stoves averaged $2-3. Thus, the cost of switching to an improved stove was not insignificant for most rural households in Africa.
18. Using the following conversion factors: 1 kg of charcoal = 30.8 MJ = 0.00074 toe.

Improving the efficiency of rural bioenergy use could have a real impact not only on the standard of living for rural populations but also on the sustainability of future bioenergy use and supply. The following analysis estimates the cost of providing efficient cooking stoves to the off-grid, rural population in developing countries.[19]

Box 5.1: **Costs and Efficiencies of Improved Cookstoves in Developing Countries**[20*]

In China, most of the stoves distributed in the early 1990s cost between $12 and $18. The average current cost of an improved stove is around $10. These stoves improve efficiency by some 20% to 30%. In India, improved chulhas (cookstoves) are estimated to cost between $3 and $4.50 and increase efficiency by 20% to 35%, depending on the stove model.

The most widely used improved stove model in Latin America is the Lorena stove, built from sand and clay. The Lorena stove with a chimney, reduces indoor smoke, increases fuel efficiency up to 10% and costs some $10. More expensive cookstoves tested in Latin America improved efficiency from 20% to 40%.

In Africa, the cost of improved stoves has fallen because of increased competition among manufacturers and vendors, which has spurred innovation in both the materials used and the methods of production. Improved cookstoves now average $1 to $3. The Lakech improved charcoal stove in Ethiopia cost about $1 and increased efficiency by more than 35%. On average, improved stoves tested in Africa were 30% to 40% more efficient than traditional stoves.

Table 5.13 shows the range of costs to households in China, India, Sub-Saharan Africa and Latin America of an improved cookstove. These stoves are currently on the market in developing countries and provide the efficiency improvements indicated in Box 5.1. The population which may

19. For a comprehensive assessment of the cost and efficiency of improved cookstoves in Asia, see RWEDP (www.rwedp.org).
20. The information in Box 5.1 was obtained from the following sources: http://www.rwedp.org/d_technodc.htm, Natarajan (1999) and Still et al. (2000).

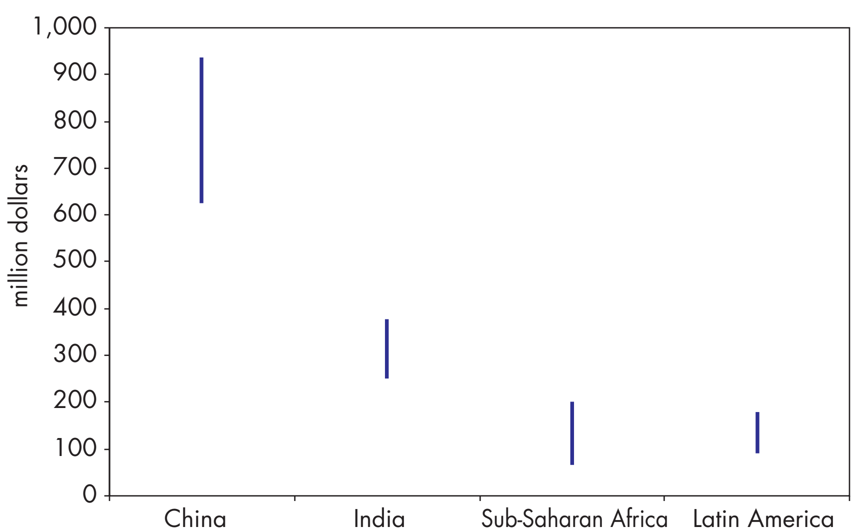
switch to more sustainable use of bioenergy is estimated to be 1.5 million people, or some 60% of the total population which uses bioenergy currently.[21] Nearly half the people using bioenergy for cooking live in India and China. Another third lives in Sub-Saharan Africa.

Table 5.13: **Costs of Improved Cookstoves in Developing Countries**

	Population that might switch to improved cookstoves (million)	**Range of purchase prices of improved cookstoves**
Developing Countries	**1,504**	**$1 –$20**
China	390	$8 – $12
India	420	$3 – $4.50
Latin America	45	$10 – $20
Sub-Saharan Africa	336	$1 –$3

Source: FAO, RWEDP and Aprovecho Research Center, USA.

Figure 5.2: **Range of Investment Requirements to Provide Improved Cookstoves**



Source: IEA analysis.

21. FAO estimate on sustainable bioenergy use.

Figure 5.2 indicates the range of investment required to supply improved bioenergy cookstoves to some 240 million households in China, India, sub-Saharan Africa and Latin America. Assuming that a typical household in these countries consists of five family members, the money required to supply improved cookstoves would be between $1 and $2 billion. The potential energy savings from the switch to more advanced cookstoves is presented in Table 5.14. Bioenergy use in rural households, shown in Table 5.14, is based on 1997 bioenergy consumption data.[22] The range of efficiency improvements is based on the assumptions in Box 5.1. A switch to improved cookstoves, with the efficiency improvements indicated in Table 5.14, could save over 500 million tonnes of fuelwood.

Table 5.14: **Potential Energy Savings in Developing Countries from Improved Cookstoves**

	Rural household bioenergy use (Mtoe)	**Efficiency improvements (%)**	**Energy savings** (Mtoe)	**Maximum fuelwood savings** * (million tonnes)
China	198	20 – 30	40 – 59	180
India	168	20 – 35	34 – 59	178
Latin America	28	10 – 40	3 – 12	36
Africa	116	30 – 40	35 – 46	141

* Using the conversion factor: 1 tonne of firewood = 0.33 toe.
Source: IEA analysis.

Biogas

The use of biogas as a clean fuel for cooking to replace scarce fuelwood has received considerable attention over the last three decades. Biogas is mostly produced from animal waste, and its use requires a plentiful supply of cows or other livestock to provide fuel. Biogas can also be produced from crop residues.

22. The share of rural bioenergy in households differs among countries. In China and India, the household sector accounts for over 90% of bioenergy use. In Africa, this share is some 80%. The household sector in Latin America, however, accounts for only some 20% of total bioenergy use.

Cooking with biogas offers advantages over traditional direct bioenergy burning, including more efficient use of bioenergy resources, reduced indoor smoke and reduced time spent collecting fuel. Biogas programmes have had low success rates. The most important reason for the failure of biogas technology is that the initial cost is often prohibitive for most rural households. The typical cost of a simple, unheated biogas plant, excluding the cost of land, is between $50 and $75 per cubic metre capacity.

Prospects

Bioenergy use for industrial and residential heat production is expected almost to double in OECD countries over the next two decades, but it will still account for less than 4% of total final energy consumption in 2020. Growth will be stronger in OECD Europe, resulting from programmes aimed at deploying renewable technologies, direct and indirect subsidies and renewable energy purchase obligations, many of which are already in place.

Table 5.15: **Bioenergy Use in Developing Countries**

	1997 (Mtoe)	**Share in TFC (%)**	**2020** (Mtoe)	**Share in TFC (%)**
China	208	25	220	15
East Asia	100	21	102	11
India	193	54	219	33
Rest of South Asia	48	58	70	42
Brazil	34	25	36	16
Rest of Latin America	44	15	46	8
Africa	206	59	309	53

Source: IEA (2000).

Using bioenergy energy in an efficient and sustainable way will require significant government intervention. In the OECD, those countries with the greatest share of bioenergy in their energy balances have correspondingly greater incentives promoting its use. Realising the future potential of bioenergy will require major investment in development and deployment of technologies and increased expenditures on R&D. The potential for bioenergy use over the long term depends on overcoming the many barriers which impede its market penetration. High cost per unit of output, high initial investment costs, and lack of funding for projects are major financial barriers.

Hydropower Supply Prospects

Hydropower Resources

Hydropower is the world's largest renewable energy source. Its unexploited potential is still vast, particularly in developing countries. In the OECD, the best sites have already been developed, although there remains some room for upgrading existing capacity. Table 5.16 shows the technical hydro potential by region. The developing regions account for more than 60% of it. The transition economies also have significant resources, especially Russia. Current world hydroelectricity production exploits 18% of the technical potential. In developing regions, this share is 12%.

Table 5.16: **World Hydropower Potential**

	TWh per year
OECD North America	1,480
OECD Europe	>1,103
OECD Pacific	>243
OECD	**>2,826**
Transition economies	**>2,392**
Latin America	>2,980
China	1,920
East Asia	1,197
South Asia	958
Middle East	218
Africa	>1,888
Developing Countries	**>9,161**
World	**>14,379**

Source: WEC (2001).

Supply Costs

Hydro is a capital-intensive option for electricity generation, but the cost per unit of electricity generated is low in good sites. High initial investment is an important issue. Developing countries may find it difficult to raise the funds to finance new projects.

Environmental Issues

The environmental and social effects of large-dam construction are the subject of much controversy. Large-scale hydropower may disturb local ecosystems, reduce biological diversity or modify water quality. It may also cause socio-economic damage by displacing local populations. A number of projects in developing countries have been stalled or scaled down because of such problems. Although these ill effects can be managed and mitigated to some degree, they may affect the future of hydropower in general. Obtaining loans from international lending institutions and banks for major projects has become more difficult. Mini- and micro-hydro systems have relatively modest and localised effects on the environment, but the kWh cost is generally higher in smaller systems.

Hydropower emits some greenhouse gases on a life-cycle basis (especially methane generated by decaying bioenergy in reservoirs), but emits far less than the burning of fossil fuels.

Overview

Hydropower provided 18% of global power in 1999. Table 5.17 shows hydro-electricity generation data for 1999 by region.

Prospects

At the end of 1997 installed hydro capacity reached 738 GW worldwide. The *WEO 2000* expects 340 GW of new capacity to be constructed over the projection period, with global electricity production from hydro plants increasing by 1.8% a year. Nonetheless, hydropower's share in electricity generation will decline to 15% by 2020.

Most of the best sites in OECD countries have been exploited, and environmental concerns limit new construction, but Canada, Turkey and Japan are expected to develop their hydro resources further. Hydroelectricity in the OECD is projected to grow by only 0.5% per year over the projection period.

Table 5.17: **Hydroelectricity Production, 1999**

	Production (TWh)	**% of Total Electricity**
OECD North America	634	14
OECD Europe	509	17
OECD Pacific	127	10
OECD	**1,270**	**14**
Transition economies	**282**	**20**
Latin America	555	60
China	204	16
East Asia	80	10
South Asia	110	18
Middle East	15	3
Africa	69	17
Developing Countries	**1,033**	**23**
World	**2,584**	**18**

Source: IEA data.

Developing countries account for 80% of the projected increase in hydroelectricity between now and 2020, three-quarters of that in China and Latin America. Competing uses, such as for water supply, irrigation and flood control, are likely to influence the decision for the development of new hydropower projects.

Geothermal Energy Supply Prospects

Geothermal Resources

Geothermal energy is the thermal energy stored in rocks and fluids in the earth's interior. The temperature of the earth increases with depth by 3°C every 100 meters. In some places, however, because of unusual geophysical activity, hot or molten rock comes closer to the surface, creating high-temperature pockets at more accessible depths.

Geothermal resources are classified according to the thermodynamic properties of the extracted fluid and their geological characteristics. There is no uniform temperature-based classification. One system classifies resources as low-enthalpy (with temperatures ranging from 30°C to 150°C) or high-enthalpy (temperatures above 150°C).[23] According to the

23. IEA (1987).

Geothermal Resources Council in the USA, resources are classified as low temperature (less than 90°C), moderate temperature (90°C - 150°C), and high temperature (greater than 150°C).[24] The higher temperature resources (starting at about 95°C) are used for electricity generation while the lower-grade source (up to 150°C) is used directly to provide heat for various applications.

Depending on geological conditions, geothermal resources are classified as hydrothermal, geopressured, and hot dry rock.

Hydrothermal resources are the only ones commercially exploited today. They are found at depths from 100 to 4500 meters and contain vapour only or vapour and water. Temperatures are in the range of 90°C to 350°C with about two-thirds of the reserves in the moderate-temperature range (150°C to 200°C).

Geopressured resources are hot water aquifers that sometimes contain dissolved methane under high pressure. They are located in depths between 3 km and 6 km. Temperatures of geopressured reserves range between 90°C and 200°C. This type of resource is rare and the major resource area identified today is in the Northern Gulf of Mexico region and in California, USA.

Hot dry rock resources are geological formations that contain little or no water and have temperatures above 150°C. These resources are widely available at many different depths, usually deeper than hydrothermal resources. This type of resource is expected to form of geothermal energy.

The most important zones of geothermal resources by region are:[25]

- **OECD North America:** Western parts of the US (including Alaska) and Canada.
- **OECD Europe:** Iceland, the Azores, and the Canary Islands. In the Mediterranean, Italy, Greece and Turkey. In Northern Europe, geothermal resources are suitable mostly for heating purposes.
- **OECD Pacific:** Japan and New Zealand.
- **Transition economies**: Eastern parts of Russia, western Siberia.
- **China**: Eastern China, Himalayan region.
- **South Asia:** The Himalayan geothermal belt.
- **East Asia:** The Philippines and Indonesia.

24. Geothermal Resources Council (www.geothermal.org).
25. Geothermal Education Office (geothermal.marin.org).

- **Latin America:** Eastern and central parts of Mexico. Other countries in the Central American and the Andean volcanic belt.
- **Africa:** East African Rift (Kenya, Tanzania, Ethiopia, Zambia, Malawi, Uganda, Djibouti, Egypt). Some in North Africa.
- **Middle East:** The Red Sea-Jordan Valley Rift (Israel, Jordan) resources, suitable for bathing and heating.

Geothermal Electricity

Technology

The higher the temperature, the shallower the resource, and the more drillable the rock, the more economic it is to produce electricity. Current technology focuses on hydrothermal resources. The most commonly used technologies used for electricity production from hydrothermal reservoirs are flash steam and binary cycle.

Supply Costs

The investment in the development of a geothermal field, including exploration and drilling, can range from 15% to 50% of the capital cost of the system, with the cost being at the low end for very high temperature sites with high permeability. This stage of the project involves some investment risk since there is no guarantee that drilling will be successful. Drilling operations are similar to those used in the oil industry and therefore the development of geothermal projects could benefit from technological advances in the oil industry. Such advances would help reduce costs and uncertainty.

The most important factors influencing the cost of geothermal plants are:

- *the temperature of the resource.* A high-temperature resource produces more energy per unit of produced fluid.
- *the depth of the resource.* Low-depth resources involve less drilling and their development is therefore less costly.
- *the type of the resource.* Dry-steam resources are less expensive to develop because they do not require separators, reinjection pipelines and wells. Dry steam is found only at reservoirs that are partially dried out, and these have depleted rather rapidly, such as at The Geysers, US and in Larderello, Italy.
- *the chemistry of the geothermal fluid.* A resource with high concentrations of chemicals often creates technical problems that

may incur extra costs. Usually the worst chemistry problems occur in high temperature reservoirs where flash technology is used, rather than in low- to moderate-temperature reservoirs where binary technology is used.

- *the permeability of the resource*. High permeability of the geothermal reservoir means higher well productivity and fewer wells needed to produce fluid for the power plant.
- *the location of the geothermal field*. Costs are higher in isolated areas, where the cost of infrastructure, such as access roads and transmission lines may be higher. Difficult terrain and earthquake conditions also add to the cost.

The technology of the plant also affects the cost. Binary plants are more expensive to build than plants using flash-steam technology. Geothermal technology is capital intensive and in most cases the development of geothermal power plants requires financial support from government. Table 5.18 shows ranges of capital costs for geothermal power plants for different plant sizes and resource quality.

Estimates of electricity generating costs of geothermal plants vary widely with location. The World Bank reports costs in the range of 2.5 cents to 10.5 cents per kWh for projects in developing countries. The lower end of the estimates is for large installations with high-quality

Table 5.18: **Capital Costs of Geothermal Power Plants ($/kW)**

Plant Size	Resource Quality	High	Medium	Low
Small (<5 MW)	Exploration: Steam field: Power plant: Total:	400-800 100-200 1,100-1,300 1,600-2,300	400-1,000 300-600 1,100-1,400 1,800-3,000	400-1,000 500-900 1,100-1,800 2,000-3,700
Medium (5-30 MW)	Exploration: Steam field: Power plant: Total:	250-400 200-500 850-1,200 300-2,100	250-600 400-700 950-1,200 1,600-2,500	Normally not suitable
Large (>30 MW)	Exploration: Steam field: Power plant: Total:	100-200 300-450 750-1,100 1,150-1,750	100-400 400-700 850-1,100 1,350-2,200	Normally not suitable

Source: World Bank.

resource. Estimates from the US Department of Energy are on the order of 5 cents to 8 cents per kWh. The WEO estimates for good quality resources likely to be developed over the next twenty years are in the range of 3 cents to 4 cents per kWh.

Environmental Issues

Geothermal plants may release gaseous emissions into the atmosphere during their operation. These gases are mainly carbon dioxide and hydrogen sulphide with traces of ammonia, hydrogen, nitrogen, methane, radon, and the volatile species of boron, arsenic and mercury. This characteristic could slow the future development of geothermal resources, although emission concerns have not been significant enough to stop the development of geothermal plants. The issue of emissions has been addressed, in many cases, through strict regulations and by control methods used by the geothermal industry to meet these regulatory requirements. Hydrogen sulphide abatement systems reduce environmental damage but they are costly to install.

Overview

World electricity production from geothermal facilities in 1999 was 50 TWh equivalent to 0.3% of total electricity generation. Geothermal energy is the third largest source of renewable electricity after hydro and bioenergy. As Table 5.19 shows, the United States is the largest geothermal electricity producer in the world, although the share of geothermal in the country's total electricity is very small, followed by the Philippines, where its contribution to the electricity mix is substantial.

In recent years, most of the growth in geothermal electricity has come outside the OECD. Indonesia and the Philippines accounted for nearly 60% of the increase between 1990 and 1999. Within the OECD, most incremental production was in Italy, where geothermal electricity generation increased from 3,222 GWh in 1990 to 4,403 GWh in 1999. Geothermal is Italy's most important source of renewable electricity. Geothermal also increased substantially in Japan, where it doubled over the period 1990-1999.

Prospects

Over the next twenty years, geothermal electricity is expected to increase almost three-fold. Most of the growth is likely to come in the Pacific region, notably in East Asia. The *WEO 2000* projections of global geothermal electricity are shown in Table 5.20. Cost reductions are expected in exploration and drilling and in conversion systems.

Table 5.19: **Geothermal Electricity Production, 1999**

	GWh	% of Country's Total Generation
USA	17,381	0.4
Philippines	10,594	25.6
Mexico	5,623	2.9
Italy	4,403	1.7
Japan	3,451	0.3
Indonesia	2,728	3.2
New Zealand	2,502	6.6
Iceland	1,136	15.8
Costa Rica	804	13.0
El Salvador	598	15.8
Kenya	390	8.6
Nicaragua	102	4.7
Turkey	81	0.1
Portugal	80	0.2
Russia	28	0.0
Ethiopia	26	1.6
Romania	3	0.0
World	**49,930**	**0.3**

Source: IEA data.

Table 5.20: **Global Geothermal Electricity (TWh)**

	1997	2020
OECD North America	14.9	25.1
OECD Europe	4.4	7.5
OECD Pacific	5.8	23.6
Transition Economies	0	0.9
China	0	2.5
South Asia	0	0
East Asia	9.8	38.1
Latin America	6.9	11.2
Africa	0.5	3.1
Middle East	0	0
World	**42**	**112**

Source: IEA (2000).

Geothermal Heat

Geothermal heat is produced from reservoirs with temperatures from 30°C to 150°C. An estimated 55 countries in the world use geothermal heat with an installed thermal capacity of 17,175 MWth in 1999.[26] The USA has the largest installed capacity in the world, 5,366 MWth in 1999, followed by China with 2,814 MWth and Iceland with 1,469 MWth.

Geothermal heat is produced either directly or by using heat pumps. Hot water can be used directly for heating buildings and in many commercial and industrial applications such as in greenhouses, in aquaculture and in water cures.

Geothermal heat pumps use the relatively constant temperature of soil or surface water to provide heating and cooling for buildings. They have higher initial costs than conventional systems but their maintenance and operating costs are low.

Wind-Power Supply Prospects

Wind-Power Resources

Wind resources are available globally. The technically available wind potential greatly exceeds current electricity demand worldwide. Grubb and Meyer have calculated global wind potential of more than 50,000 TWh per year, while Wijk and Coelingh estimate it at 20,000 TWh per year.[27] Although similar in magnitude, it is worthwhile to note that the estimates were derived using different assumptions. The first estimate corresponds to about 10% of the gross theoretical potential in windy areas, which are 23% of global land area.[28] The second estimate assumes that 4% of the area that is exposed to average wind speeds higher than 5.1 metres per second (m/s) at 10 metres height is available for the development of wind farms.[29] Table 5.21 shows the regional distribution of wind power potential according to Grubb and Meyer.

Table 5.22 shows the classification of wind-energy resources used by the US Department of Energy. This classification is based on the power density of the wind. Wind speeds are shown at two different heights, 10 metres and 50 metres. This is because wind speed increases with height.

26. Observatoire des énergies renouvelables, *Systèmes Solaires* (www.systemes-solaires.com).
27. Excluding offshore potential.
28. UNDP, UNDESA and WEC (2000).
29. WEC (1993).

Table 5.21: **Regional Wind Potential Estimates by Grubb and Meyer**

Region	**1,000 TWh per year**
Africa	10.6
Australia	3
North America	14
Latin America	5.4
Western Europe	4.8
Eastern Europe and FSU	10.6
Asia	4 .9
World	**53**

Table 5.22: **Classes of Wind Power Density at 10 m and 50 m**

	10 m high		**50 m high**	
Wind Power Class	**Wind Power Density** ($Watt/m^2$)	**Speed** (m/s)	**Wind Power Density** ($Watt/m^2$)	**Speed** (m/s)
1	0-100	0-4.4	0-200	0-5.6
2	100-150	4.4-5.1	200-300	5.6-6.4
3	150-200	5.1-5.6	300-400	6.4-7
4	200-250	5.6- 6	400-500	7-7.5
5	250-300	6.0-6.4	500-600	7.5-8.0
6	300-400	6.4-7	600-800	8-8.8
7	400-1,000	7-9.4	800-2,000	8.8-11.9

Source: US DOE (1986).

Most estimates of wind resources do not include offshore potential, which is large. The offshore potential for Europe is shown in Table 5.23.

Technology

Wind technology converts the energy available in wind to electricity or mechanical power through the use of wind turbines. The most important components of a wind turbine are:

- the drive train, which contains the most important parts of the wind turbine: the gearbox and the generator.

Table 5.23: **European Offshore Potential** (TWh per year)

	Distance from Shore		
Water Depth (m)	**Up to 10 km**	**Up to 20 km**	**Up to 30 km**
10	551	587	596
20	1,121	1,402	1,523
30	1,597	2,192	2,463
40	1,852	2,615	3,028

Source: EWEA *et al.* (2000).

- the rotor, which is an assembly of blades, hub and the shaft. The blades transfer the wind's power into the hub. A low-speed shaft connects the hub to the gearbox. Power is then transferred to the high-speed shaft and drives the generator.
- the tower, which carries the nacelle and the rotor.
- the electronic control system, which monitors the functioning of the turbine.
- the support structures, electrical interconnections and service facilities.

Supply Costs

As discussed above, the resource base is not an inherent constraint to the development of wind power. The challenge lies in delivering this potential to the markets at competitive costs. The main factors that influence the cost of electricity from wind power are examined below:

Capital cost: The capital cost includes the cost of turbines, their installation and grid-connection costs. Turbine costs have declined as the size of wind turbines has increased and manufacturers have increased production volume. In addition to cost reductions, improved blade designs and control systems have enhanced turbine efficiencies, thus lowering the cost of producing a unit of power. Some recent estimates of investment and generating costs of wind farms are summarised below:

The location of a wind farm may have a major impact on the investment cost. Because of the wide distribution of the wind resource, investment costs may increase if wind farms are located away from existing transmission lines. Grid reinforcement may be required in remote areas. Losses will tend to be higher if electricity is transmitted through low-voltage lines and for longer distances. Moreover, there may be limits to

Table 5.24: **Recent Wind Power Cost Estimates**

Country	Investment Cost ($/kW)	Generating Costs (cents/kWh)
Germany[30]	1,308-1,417 (onshore) 1,907 (offshore)	9.3 (onshore) 8.2 (offshore)
Netherlands[31]	967 1,310-1,451 (onshore) 2,011 (offshore)	n.a. n.a.
France[32]	1,199	4.6-6.8
Spain[33]	922 (turbines 75% of this cost)	n.a.
Denmark[34]	906-1,094 (onshore, turbines 80% of this cost) 1,300-1,550 (offshore)	n.a.
USA[35]	983	n.a.
Japan[36]	1,932-2,195 (in 1999) 1,317-1,756 (in 2010)	14-15 (in 1999) 10-11 (in 2010)
Australia[37]	1,161-1,742 (turbines 60%-70% of this cost)	n.a.

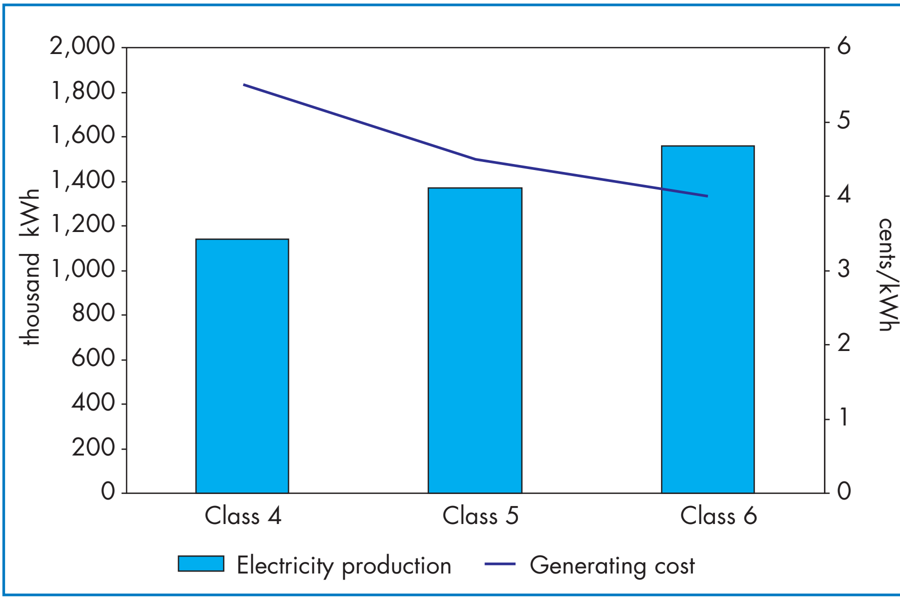
building new transmission lines in some areas. The issue of transmission costs may become more important in the future as the best locations near transmission lines are used first.

Influence of Wind Conditions on Economics: Locations with higher wind speeds and with winds available for longer periods produce more electricity. Figure 5.3 is an illustrative example of how generating costs decline from low to high classes of wind (it is based on the US classification shown in Table 5.22). It shows annual electricity production in each class (left-hand axis) and the corresponding electricity generating costs (right-hand axis).

30. Nitsch, J. *et al.* (2000).
31. IEA R&D Wind Implementing Agreement (1999) and Dutch Ministry of Economic Affairs.
32. DGEMP (1997).
33. IDAE (Institute of Diversification and Savings), Spain (www.qsystems.es).
34. Danish Energy Agency (1999).
35. Energy Information Administration, US DOE (www.eia.doe.gov).
36. Ministry of Economy, Trade and Industry (METI).
37. Australian Greenhouse Office (1999).

Wind speed increases higher above ground. Higher wind speeds can be obtained by building higher towers. Taller towers may increase capital costs, but they reduce generating costs.

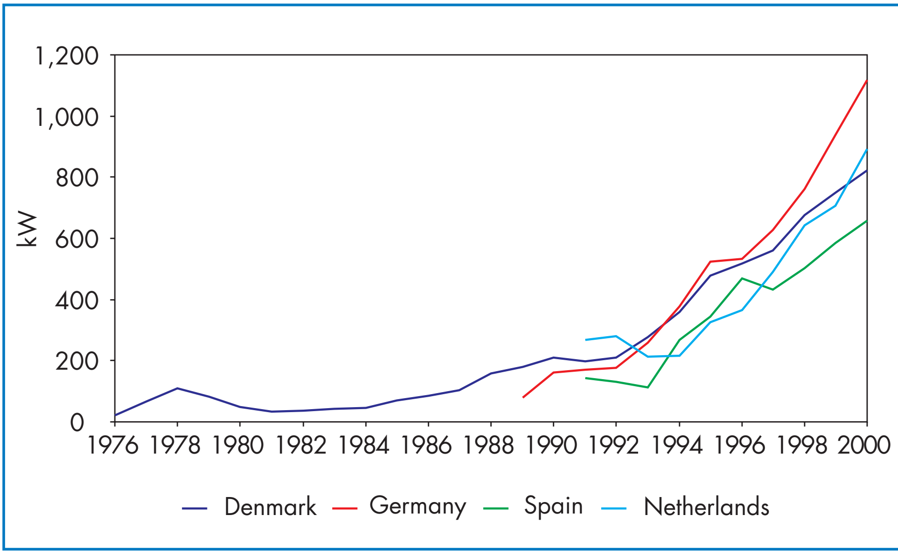
Figure 5.3: **Electricity Generating Costs of Wind at Different Wind Classes**



Source: IEA analysis.
Note: Electricity output data from EPRI and US DOE (1997).

Influence of Technology on Economics: Wind turbines come in different sizes and may be tailored for specific applications, most notably the very large machines for the offshore market. Figure 5.4 shows the average size of wind turbines installed in European countries. The average size of those installed in 2000 was 823 kW in Denmark, 1,118 kW in Germany, 657 kW in Spain and 892 kW in the Netherlands. The increase in turbine size has brought cost reductions per kW of installed capacity because of economies of scale. A key feature that has helped increase electricity output and has therefore contributed to cost reductions per unit of electricity produced is the rotor diameter of wind turbines. Larger rotors have brought cost reductions through economies of scale.

Figure 5.4: **Average Size of Installed Wind Turbines, 1976-2000**



Sources: European Wind Energy Information Network (euwinet.iset.uni-kassel.de) and Danish Energy Agency (1999).

Grid Integration

Wind is an intermittent source of energy. Wind speeds vary on an hourly, daily, seasonal and annual basis. Wind is best suited for areas where there is a correlation between wind speed profiles and electricity demand profiles. For example, in Denmark and California wind patterns tend to match demand. But this is often not the case. There may well be strong winds in winter rather than in summer in a country marked by higher electricity demand in the summer.

The value of wind-generated electricity to the local grid is closely tied to when it is available and how predictable this availability is. Electric output from wind farms can increase or decrease rapidly, and such changes cannot generally be controlled by the producer. Thus, grid integration is likely to be a critical issue in the development of wind power. Transmission operators set targets for reliability based on expected demand and expected capacity available at the time of the demand. Intermittence and low overall capacity factors reduce wind's value in meeting peak demand. One way to deal with this issue is to make available equivalent firm conventional capacity or energy-storage capacity, but increasing reserve margin entails extra costs.

A relatively low proportion of wind power in power generation might be acceptable, without the need to add new conventional capacity. In the near term, therefore, this issue is not likely to be a barrier to the development of wind power. It could become more important, however, as the share of wind in total installed capacity increases. Should this occur, wind producers would have to find ways of mitigating the higher costs resulting from intermittence. The main way to do this is by aggregation with other generators, particularly those that can follow the variations in the wind farm's output. The intermittence issue is closely intertwined with network organisation. Decentralised forms of network organisation based on bilateral contracts may help exploit wind power by shifting the intermittence issue directly to users, who are in the best position to deal with it by using various market mechanisms.

The intermittence of wind power may become an important issue in competitive electricity markets where generators have to submit bids in advance. The New Electricity Trading Arrangements (NETA) in the UK, requires that a generator who has a shortfall in contracted generation must pay for that shortfall at the System Buy Price. Due to the intermittent nature of wind, the output of these generators is more exposed to this penalty.

Better forecasting models need to be developed in the future. Advances in power electronics and better control devices are also necessary. Energy storage may help mitigate the effect of intermittence, but it is likely to remain a costly option in the medium term.

Land Use

Although not much land is needed for the installation of each turbine, they must be spaced several rotor diameters apart, so wind farms have extensive land requirements. Assuming an average land use factor of 0.12-0.15 km^2/GWh, 2% of Germany's total land area would be used by windfarms if 10% of the country's current electricity demand were produced from wind turbines. Competing uses, such as agriculture, forestry or tourism, may limit the sites available for windfarm development. At the same time it should be noted that the "footprint" of a windtower is small so that other use could be made of most of the wind farm area including agricultural activities as in Denmark.

Environmental Issues

Wind-power generation is free of pollutants but has a number of environmental effects that may limit its potential. The most important effects on the environment are:[38]

Visual effects: This is perhaps the most important and most discussed issue. Wind turbines must be in exposed areas and are therefore highly visible. They are considered unsightly by some people.

Noise: Wind turbines produce two different types of noise: aerodynamic noise, from air passing over the blades; and mechanical noise from the moving parts of the turbine, especially the gearbox. Better designs have reduced noise, and research on this issue continues. Wind farms developed far from highly populated areas are, by definition, less offensive.

Electromagnetic interference: Wind turbines may scatter electromagnetic signals causing interference to communication systems. Appropriate siting (avoiding, military zones or airports) can minimise this impact.

Bird safety: Birds get killed when they collide with the rotating blades of a turbine. Migratory species are at higher risk than resident species. Siting the turbines out of migratory routes reduces the impact.

Overview

Global wind generating capacity stood at 8 GW at the end of 1997 accounting for 0.2% of the world's total installed electricity capacity. It rose to 9 GW in 1998 and to almost 13 GW in 1999. Table 5.25 shows the breakdown of 1999 global wind capacity by region. Nearly 90% of the capacity is installed in OECD countries, where various government policies and measures have been put in place to stimulate growth in renewable energy. The largest capacity increase has been in Germany, where installed wind capacity is the highest in the world, about one third of the total.

Electricity production from wind power received increased attention after the oil crises of the 1970s. In the 1980s almost all growth was concentrated in the United States and Denmark, but an increasing number of countries turned to wind power in the 1990s, as a result of strong government support and declining costs. Wind power now is the fastest growing renewable energy resource, and perhaps the fastest growing of any energy resource.

38. See also IEA (1998).

Table 5.25: **Installed Wind Capacity, 1999**

	MW	Share of Global Wind Capacity
OECD Europe	8,706	69%
OECD North America	2,329	19%
OECD Pacific	74	1%
Transition economies	10	0.1%
China	261	2%
East Asia	7	0.1%
South Asia	1,065	8%
Latin America	82	1%
Africa	35	0.3%
Middle East	19	0.2%
World	**12,588**	**100%**

Source: IEA data for OECD regions and BWE (www.wind-energie.de) for non-OECD regions.

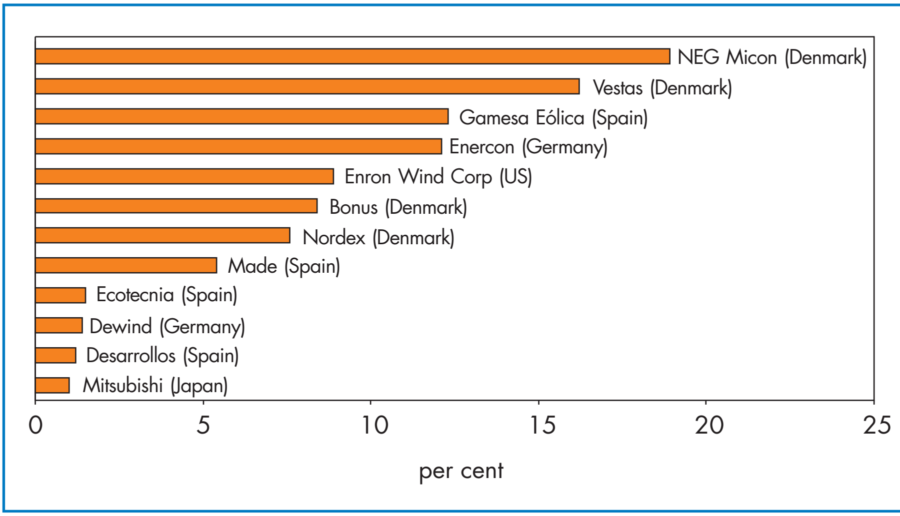
In the United States, federal and state incentives encouraged the deployment of wind power in early to mid-1980s. After an initial boom, the expiry of the incentives and a decline in fossil fuel prices slowed the trend. By 1990, wind capacity in the USA had risen to only 1.4 GW. It reached 1.8 GW in 1993 and then declined for a few years. Renewed interest in wind, supported by a number of incentives, has resulted in recent capacity increases in the USA. Wind capacity additions in 2001 could be on the order of 2 GW. This growth is due to a combination of state mandates and a production-tax credit. The latter was introduced by the Energy Policy Act of 1992. It amounts to 1.5 cents per kWh, adjusted for inflation from a 1992 basis.[39]

In Denmark, growth in wind power was strongly encouraged by government through a number of energy plans, starting with the "Danish Energy Policy 1976". Since this time, Denmark has developed a large wind-turbine-manufacturing industry. Danish companies hold a large share of the global wind turbine market and Denmark has the highest share of wind in its electricity-generation mix of any country in the world. In 1999, about 8% of the country's electricity generation came from 1.8 GW of wind-turbine capacity. Up till 1989, the government offered subsidies

39. The inflation-adjusted production tax credit for 2000 is 1.7 cents per kWh.

that covered 30% of the installation costs.[40] And until 1 April 2001, a production subsidy of 3.9 cents per kWh was paid to private wind turbine owners. Utilities were obliged by law to buy electricity from wind turbines at a rate of 85% of the utility's production costs. Denmark is switching to a market for green certificates in 2003.

Figure 5.5: **Wind Turbine Market Shares in MW Sales, 1999**



Source: Dresdner Kleinwort Wasserstein (2001).

Germany's spectacular increase in wind capacity in recent years, to 4 GW in 1999, can be almost entirely attributed to the "Electricity Feed Law" (EFL) that came into force in 1991. That law obliged utilities to buy electricity from wind turbines at 90% of the average pre-tax retail price. In 1999, this was 9 cents per kWh. The EFL was replaced in 2000 by the "Renewable Energy Promotion Law". Under the new law, wind turbines receive 9.7 cents per kWh for the first five years of operation (or longer in low-wind areas) and 6.6 cents per kWh thereafter. Offshore wind farms receive the higher rate for nine years. Rates will drop by 1.5% per year starting in 2002.

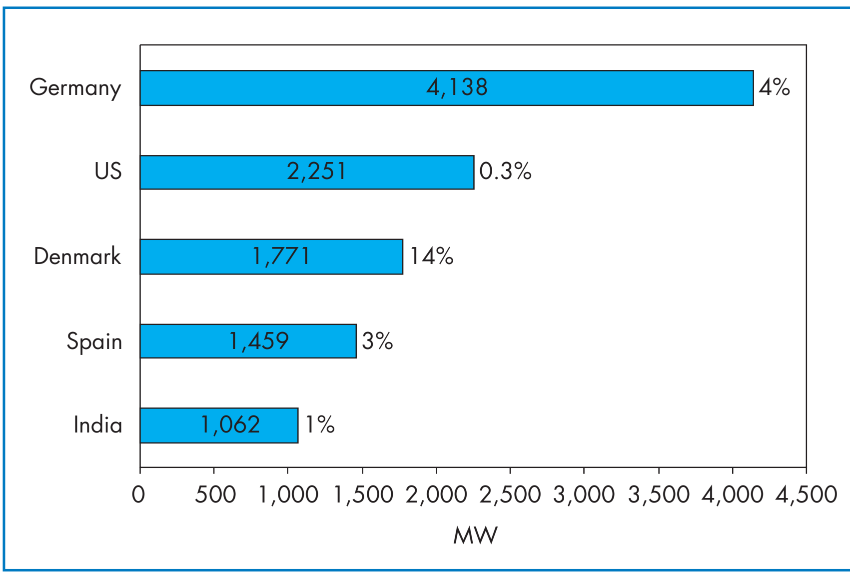
Wind capacity in Spain reached 1.5 GW in 1999. The Royal Law 2818/1998 concerning the Special Electrical Regime for Renewable Energy Plants fixed the prices and the bonus for renewable electricity

40. Danish Energy Agency (1999).

generation. Qualified renewable-energy producers have the choice of a fixed price per kWh or a variable price calculated as the average pool price plus a bonus. In 2000, the fixed price for wind farms was 5.8 cents per kWh and the bonus added to the pool price was 2.7 cents.[41]

India developed its wind resource rapidly over the past decade, and its current wind capacity exceeds 1 GW. The development of wind power started with the energy-sector reforms of 1991. It benefits from several investment-related incentives, including 100% accelerated depreciation, a 25% concessional duty on imports of complete wind generators and an exemption from duty on the import of specific components, a five-year tax holiday and various tax exemptions.

Figure 5.6: **Top Five Countries Using Wind Power, 1999**
(Installed capacity and % of total national capacity)



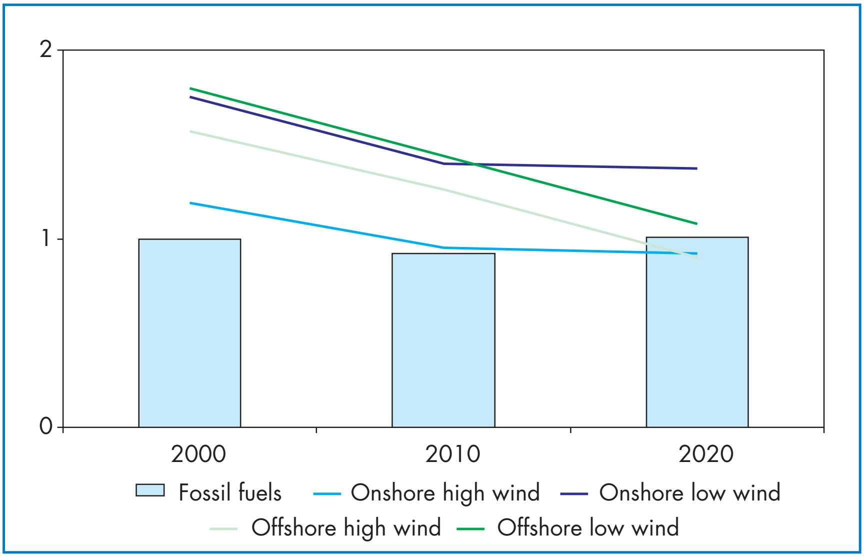
Source: IEA data.

Prospects

Despite reductions in its production costs, electricity from wind power still costs more than production from the cheapest conventional technologies in almost all circumstances.

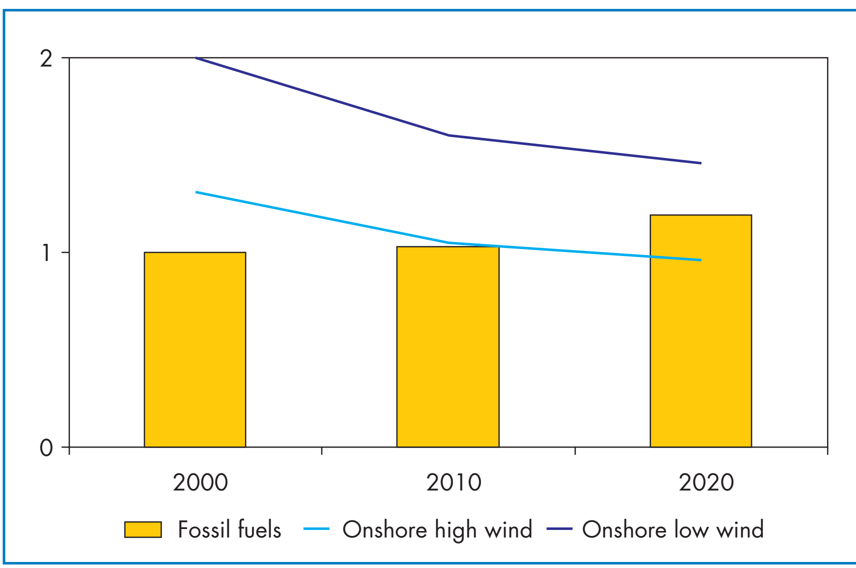
41. IEA R&D Wind Implementing Agreement (1999).

Figure 5.7: **OECD Europe Electricity Generating Costs for Wind and Fossil Fuels**
(Cheapest fossil fuel alternative in the base year equals 1)



Source: IEA analysis.

Figure 5.8: **OECD North America Electricity Generating Costs for Wind and Fossil Fuels**
(Cheapest fossil fuel alternative in the base year equals 1)



Source: IEA analysis.

The *World Energy Outlook 2000* expects that under the policies and measures included in the Reference Scenario, electricity generation from wind power will increase by 12.6% per year, from 11 TWh in 1997 to 178 TWh in 2020. In this period, wind power technology is expected to go on improving and capital costs are likely to decline with larger volumes of turbines produced. Capital costs are assumed to fall to just below $800 per kW by 2020. The trend toward building larger machines with larger rotors and taller towers is expected to continue, improving performance and reducing the unit cost of electricity. While the performance of fossil-fuel technologies is also likely to improve in the future, the difference between the electricity generating costs of wind and fossil fuels will narrow. At the best sites, wind will become competitive with the cheapest fossil fuel resources by 2010. Despite this potential cost-competitiveness, wind market growth will continue to be constrained by the technology's intermittence and by site limitations.

Figures 5.7 and 5.8 show a likely path of electricity production costs. Fossil-fuel costs are based on the assumptions used to produce the *World Energy Outlook 2000*. The generating costs of wind are given as a range of estimates, based on different levels of annual electricity production per unit of installed capacity. Although wind is expected to become competitive in the best sites, it should be noted that the best sites tend to be developed first, so later developments will have less favourable conditions. Improvements in technology may help to balance this effect to some extent.

Solar Energy Supply Prospects

Solar Energy Resources

The solar energy resource is abundant. The radiation received on a clear day on the earth's surface, around noon, is about 1,000 Watts per m^2. The amount of energy received at the surface is called "insolation" and is typically measured in kWh or MWh per m^2. If, for example, the solar resource were available for five hours a day on average, the annual insolation would be:

$$(5/24 \times 8{,}760) \text{ hours in a year} \times 1{,}000 \text{ Watts/m}^2) \ / \ 1{,}000 = 1{,}825 \text{ kWh/m}^2$$

In a given area, the amount of annual insolation is more or less constant, but varies seasonally. It follows that solar power can be best exploited in areas with high annual insolation, where electricity demand is

Table 5.26: **Annual Insolation in Selected Cities**

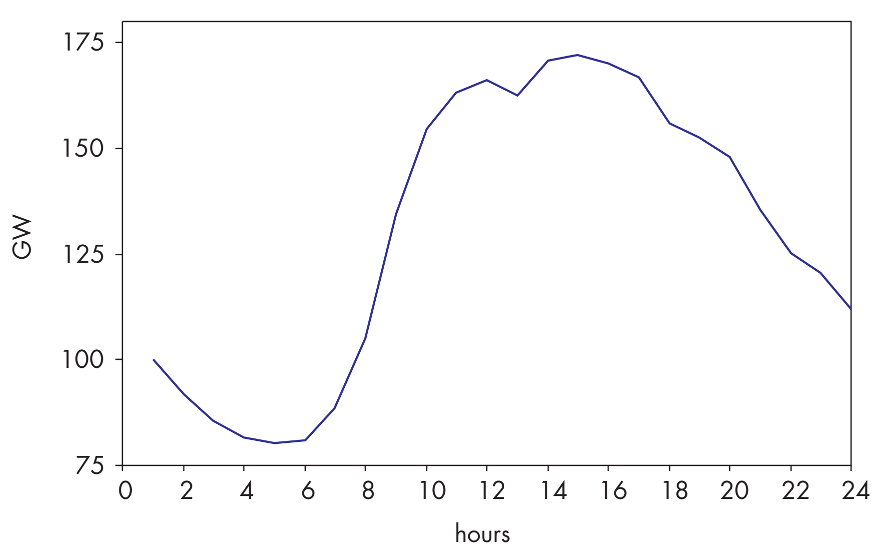
	MWh/m²
Sacramento, CA, US	1.80
Malaga, Spain	1.71
Dresden, Germany	1.00
Cape Town, South Africa	1.89
Tokyo, Japan	1.09
Brasilia, Brazil	1.80
Riyadh, Saudi Arabia	1.87

Source: RETScreen, Natural Resources Canada.

also greatest during daylight hours. Figure 5.9 shows a typical summer-day load curve for Japan.

Electricity demand in some countries is higher in the summer when the sun shines longest. Countries with summer peak include Italy, Greece, Japan, Korea, USA, Mexico and Australia. In northern Europe, demand is higher in winter months, when sunlight is limited due to very short days

Figure 5.9: **Typical Daily Load Curve, Japan**



Note: Data are for 25 August 2000.
Source: METI.

and solar power may not be available towards the end of the day, when residential demand starts to peak.

Photovoltaics

Technology and Applications

Photovoltaic (PV) technology transforms the energy of solar photons into direct electric current using semiconductor materials. The basic unit is a photovoltaic or solar *cell*. When photons enter the cell, electrons in the semiconductor material are freed, generating direct electric current (dc).

Solar cells are made from a variety of materials and come in different designs. The most common semiconductor materials used in PV-cell manufacturing are single-crystal silicon, amorphous silicon, polycrystalline silicon, cadmium telluride, copper indium diselenide, and gallium arsenide. The most important PV cell technologies are crystalline silicon and thin films, including amorphous silicon.

PV cells connected together and sealed with an encapsulant form a PV *module* or *panel*. PV modules come in standard sizes ranging from less than a Watt to around 100 Watts. When greater amounts of electricity production are required, a number of PV modules can be connected together to form an *array*.

The components needed to transform the output of a PV module into useful electricity are called "balance of system" (BOS). BOS elements can include inverters (which convert direct to alternate current), batteries and battery charge controllers, dc switchgear and array support structures depending on the use. A PV module or array and BOS form a PV *system*.

A PV cell converts only a portion of the sunlight that it receives into electrical energy. This fraction is the "efficiency" of the PV. Laboratory research has recently achieved efficiencies of 32%. In practice, efficiencies are lower.

Photovoltaic technology has a wide range of applications. The applications directly linked with electricity production are outlined below:

Stand-alone (off-grid) systems: These are PV systems that produce power independently of the utility grid. Using stand-alone photovoltaic systems can be less expensive than extending power lines and more cost-effective than other types of independent generation.

Most of currently profitable applications are remote telecommunications systems, where reliability and low maintenance are the principal requirements. PVs also have wide application in developing countries, serving the substantial rural populations who do not otherwise have access to basic energy services. PVs can be used to provide electricity for a variety of applications in households, community lighting, small enterprises, agriculture, healthcare and water supply.

Grid-connected systems in buildings: Where a grid is available, a PV system can be connected to it. When more electricity than the PV system is generating is required, the need is automatically met by power from the grid. The owner of a grid-connected PV system may sell excess electricity production. Net metering rules can promote this.

Utility-scale systems: Large-scale photovoltaic power plants, consisting of many PV arrays installed together, can provide bulk electricity. Utilities can build PV plants faster than conventional power plants and can expand the size of the plant as demand increases.

Supply Costs

The cost of a PV system includes the cost of the photovoltaic module and the BOS costs. According to the IEA's Photovoltaic Power Systems Programme, the installation cost of a typical, basic photovoltaic system ranges from $5,000 to $7,000 per kWp.[42] The cost of the module is 40-70% of the total system cost depending on the application.

Because of its flexibility, modularity and simplicity, photovoltaic technology can be a cost-effective alternative option in many remote applications in both developing and OECD countries.

A large number of PV systems has been installed in developing countries and this trend is likely to continue. Power requirements in remote areas are modest and may be limited to lighting only, or extend to a few appliances, such as televisions and refrigerators. The current cost of a 50 W PV system designed to meet the very basic needs of a rural household in a developing country is around $500. Additional expenses include maintenance costs and battery replacement every three to six years. Today, the infrastructure to deliver diesel generators and diesel fuel in rural areas is relatively well-established but PV systems may still be cost competitive where fuel has to be transported a long way.

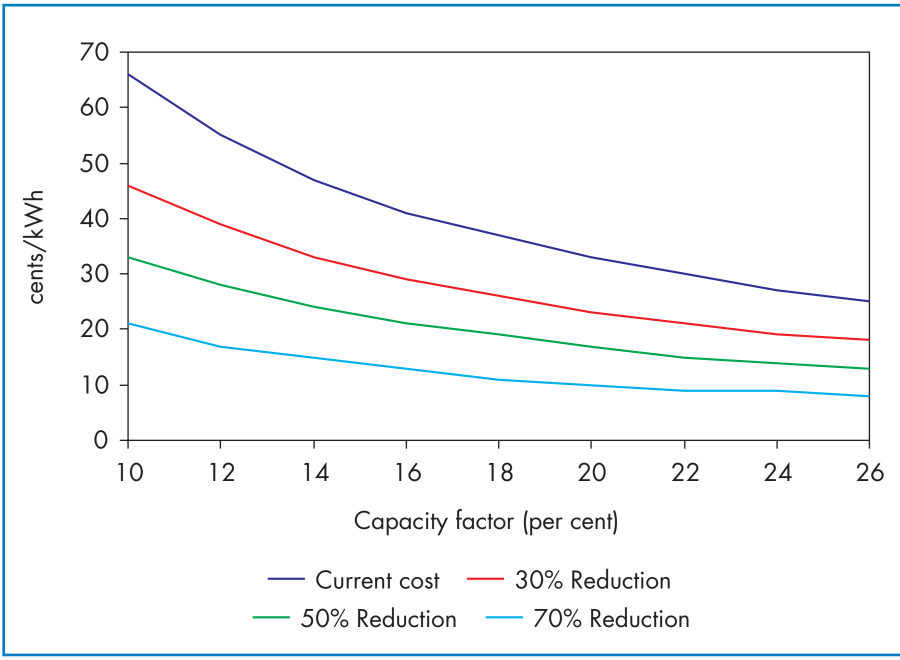
Lack of financial resources for the initial investment is a major obstacle to widespread use of PV. Future reductions in the cost of PV systems are likely. To become widely used in remote areas, however, PV

42. The capacity of a PV system is measured in Watt peak (Wp). This is the peak power under standard test conditions of 1,000 W/m^2 irradiance, 25°C cell temperature and solar reference spectrum AM1.5.

systems will require additional facilities, such as credit facilities, trained service staff, and ready access to replacement components and spare parts.

Buildings are a large potential market for grid-connected photovoltaic systems. Substantial reductions in capital costs will be necessary to make this technology commercially viable. Figure 5.10 shows electricity generating costs for today and three levels of capital cost reductions and a range of capacity factors. Capacity factors are on the order of 10% in Germany, 12% in Japan and 20-22% in California, US.

Figure 5.10: **PV System Electricity Generating Costs**



Source: IEA analysis.

The competitiveness of PV electricity in buildings depends on the price of electricity that the owner of the PV cell would otherwise have to pay to a local electricity supplier. Uncertainty over future electricity prices could be an important barrier to the development of building PV markets, although it can also be a stimulus in regions that lack generating capacity. Over the past few years electricity prices to final consumers have declined, as Table 5.27 indicates. If electricity prices increase in the future, PVs will become more competitive.

Table 5.27: **Residential Electricity Prices in Selected OECD Countries**

	cents per kWh	
	1995	**1999**
Austria	20.9	13.7
Denmark	22.7	21.2
France	18.2	13.4*
Germany	22.1	15.5
Italy	18.5	15.0
Japan	29.4	21.7
Netherlands	14.7	13.5
Spain	21.3	14.6
Switzerland	18.0	13.3
UK	13.9	11.9
US	9.2	8.3

Source: IEA data.
*1998 data.

Recognition of the environmental benefits of renewable energy may encourage some consumers to invest in PVs, despite the higher costs. This is likely to be one of the main drivers of market growth over the next twenty years.

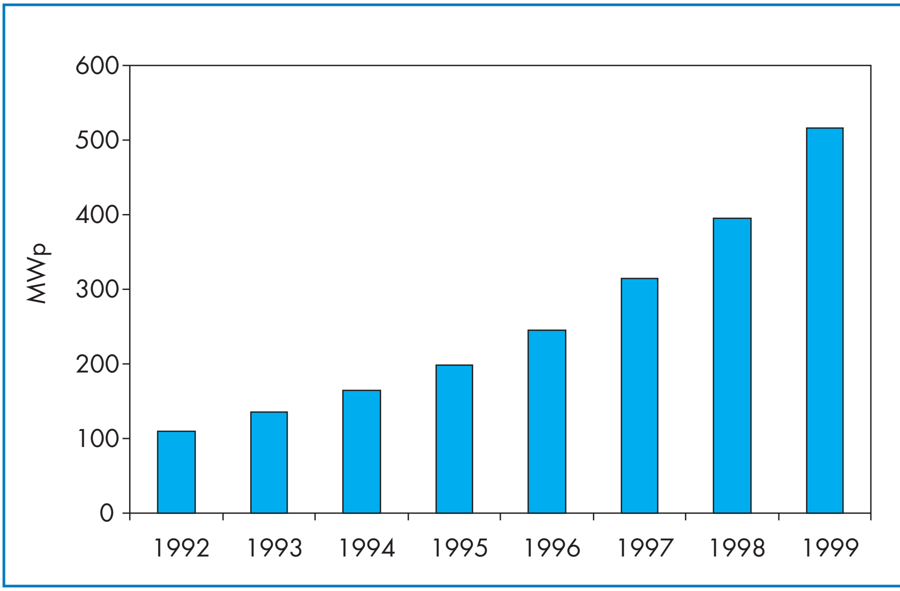
Only a small percentage of current PV capacity has been installed by utilities. It is unlikely that PV technology for utility-scale generation will become competitive over the next twenty years. Even if it did so, utilities are likely still to prefer to meet peak load with dispatchable devices with very low capital costs, such as gas turbines.

Overview

Data available from the IEA's Photovoltaic Power Systems Programme (PVPS) Implementing Agreement show that installed PV capacity was 516 MWp in 1999.[43] Figure 5.11 shows PV capacity increases in recent years.

43. Data are available for the following OECD countries: Australia, Austria, Canada, Denmark, Finland, France, Germany, Italy, Japan, Mexico, Netherlands, Norway, Portugal, South Korea, Spain, Sweden, Switzerland, UK, and US. Data are also available for Israel.

Figure 5.11: **PV Capacity Trends in OECD Countries**



Source: IEA PVPS Implementing Agreement.

Nearly half the total PV capacity is used in off-grid application. This share is very high in some countries. In Mexico, almost 100% of PV capacity is used in off-grid applications. The share is 92% in Australia and 72% in the USA. On-grid applications are mostly distributed (in buildings), while centralised PV production accounts for less than 7% of total PV capacity. Table 5.28 shows the countries with the highest PV capacity and its applications.

Japan has the highest PV capacity as a result of an important programme to support the development of PV markets. The "Residential PV System Dissemination Programme" which was initiated in 1997 provides investment subsidies to individuals, real estate developers and local organisations involved in public housing projects. In 2000, government support was $2,505/kW up to 10 kW and $1,670/kW up to 4 kW. PV systems were installed in nearly 19,000 homes in 2000. Since 1994, a total of 51,899 houses have installed PV systems. Figure 5.12 shows annual installations for the period 1994-2000.

Japan's installed PV capacity was 205 MWp in 1999. The country's aim is to reach 5 GW of installed capacity by 2010. To achieve this, current

Table 5.28: **Installed PV Power in Selected Countries, 1999** (MWp)

	Total Capacity	Off-Grid	On-Grid Distributed	On-Grid Centralised
Japan	205	57	146	3
US	117	84	21	12
Germany	70	12	49	9
Australia	25	23	1	1
Italy	18	11	1	7
Switzerland	13	3	9	1
Mexico	13	13	0	0
Netherlands	9	4	5	0
France	9	9	0	0
Spain	9	7	1	1

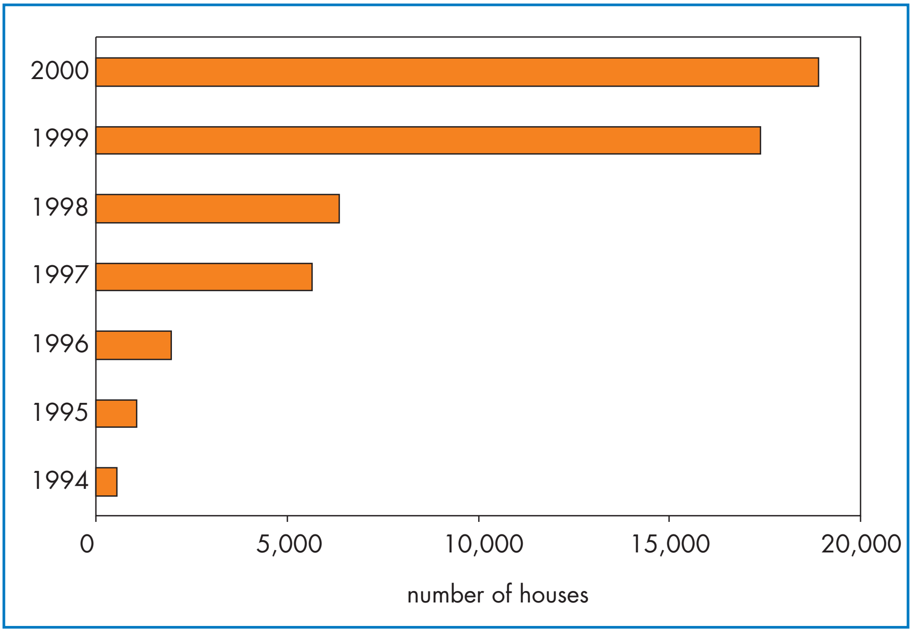
Source: IEA PVPS Implementing Agreement.

capacity must increase by a factor of 25 and annual capacity additions must average 436 MWp over the next 10 years. This is a much higher rate than the current level of annual additions. In 1999, 72 MWp of capacity were installed. Although the annual rate of installations has been increasing, substantial efforts will have to be made to meet the target.

The United States had a PV capacity of 117 MWp in 1999. The most important initiative related to PV development is the Million Solar Roofs Program, which aims at installing solar energy systems on one million US buildings by 2010. This effort includes two types of solar technology — photovoltaics that produce electricity from sunlight and solar thermal panels that produce heat for domestic hot water, space heating or swimming pools.

In Germany, there were 69.5 MWp of installed PV capacity in 1999. The 100,000 Roofs Solar Power Programme, that was initiated in 1999, provides low interest loans for 10 years. In addition to central government support, 10 of Germany's 16 federal states support PV through various incentives. The aim of the 100,000 roofs programme is to reach a total installed capacity of 300 MWp in 2003. The "Renewable Energy Promotion Law" set the buy-back tariff for PV-generated electricity at 51 cents per kWh and could encourage further PV development.

Figure 5.12: **Annual PV Installations in Japanese Houses, 1994-2000**



Source: IEA PVPS Implementing Agreement.

Prospects

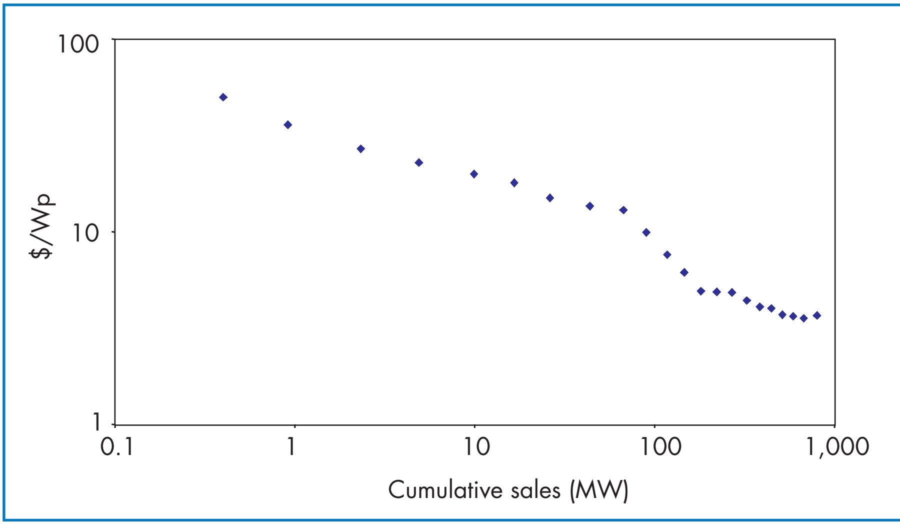
Over the next twenty years, the use of PV technology is likely to expand, but its contribution to the global electricity mix will remain relatively small. On the other hand, PV may be the best technology to meet energy needs in remote areas and for building applications. PVs are used and will continue to be used in rural electrification projects. They are an effective way to serve the substantial rural populations who do not otherwise have access to basic energy services.

Capital costs are expected to decline as demand for PV increases and larger quantities are produced. Figure 5.13 shows historical PV module cost reductions. Most of the reductions are expected to be in PV module costs, rather than in the cost of BOS. The timing and rate of future cost reductions are uncertain.

Solar Thermal for Electricity Production

Solar-thermal technologies concentrate solar radiation onto a receiver, where it is converted into thermal energy. This energy is then converted

Figure 5.13: **PV Module Prices, 1976-1997**



Source: EU-ATLAS project and Nitch (1998).

into electricity. There are a number of technology options available, although they are at different stages of deployment. The most important technologies are the parabolic trough, the central receiver and the parabolic dish. Parabolic trough is commercially available and is the least expensive solar-thermal technology. Parabolic-dish and central-receiver technologies are at the demonstration stage. They have, however, the potential to achieve higher conversion efficiencies and lower capital costs than parabolic-trough technology.

Solar-thermal technologies can be combined with fossil-fuel or thermal- storage technologies to provide firm peaking to intermediate load power. They take up a lot of space, currently 20 m^2 / kW. Their water requirements are similar to those of a fossil-fuel steam plant. Water availability could be an important issue in arid areas, which are otherwise best suited for solar thermal plants.

Solar thermal technologies have very high capital costs, about $4,000/kW, and are not yet competitive with conventional technologies. Although capital costs of solar thermal technologies are likely to fall over the next twenty years, the cost of generating electricity from them will remain high. More emphasis is likely to be given to photovoltaic rather than solar thermal technologies. The contribution of solar thermal is likely to remain a small fraction of total solar power.

Solar Thermal for Heat Production

The market for solar-thermal heating systems took off in the 1970s as a result of high oil prices. Low oil prices in the 1980s reversed the trend and many solar-thermal companies went bankrupt. Improvements, both in technology and in efficiency, have led to a recent resurgence of the industry in many countries.

In 1999, total estimated deployment of solar thermal heating in the European Union (EU) was estimated to be 8.8 million m^2.[44] Germany accounted for over 30% of total installed capacity, while Austria and Greece together accounted for another 44%. Current trends indicate that solar-collector surface in the EU could reach 87 million m^2 by 2010.[45] This is less than the EU target of 100 million m^2 put forth in the White Paper on renewable energies.

The USA is one of the world's largest users of solar-thermal collectors. Total shipments were 8.6 million square feet in 1999.[46] Heating for swimming pools accounted for some 95% of total demand in 1999, with Florida and California together accounting for over 70% of this.

In Japan, sales of solar-heating units peaked in the early 1980s. Since then, low fossil-fuel prices and the gradual elimination of subsidies on the purchase of solar hot-water heaters have led to a decline in sales. Despite this recent downturn, solar thermal systems currently account for some 15% of the Japanese water-heating market.[47] There are nearly 1.5 million buildings with solar water heaters in Tokyo.

Outside of the OECD, solar-thermal heating systems have been used in the Middle East, in South Africa and in a few developing countries. In Israel, about 30% of the buildings and all new homes use solar water heating. In South Africa, installed solar water-heating capacity is estimated to be 484,000 m^2.[48] The Department of Minerals and Energy in South Africa plans to develop a long-term programme aimed at the widespread use of solar water heating. The cumulative installed solar heating collector area in India in 1998/99 was 450,000 m^2.[49]

44. Observatoire des énergies renouvelables, *Systemes Solaires* (www.systemes-solaires.com).
45. Ibid.
46. US DOE.
47. Australian Energy News (1999).
48. Department of Minerals and Energy, South Africa (www.dme.gov.za).
49. Tata Energy Research Institute (www.teriin.org).

Solar hot-water heaters use the sun to heat either water or a heat-transfer fluid in collectors. The thermal conversion of solar energy is usually classified according to the temperatures required: low, medium or high. It can also be classified according to the specific use of the collected energy: water heating, space heating or process heat. A typical system will reduce the need for conventional water heating by about two-thirds. Sometimes the plumbing from a solar heater connects to a house's existing water heater, which remains inactive so long as the water coming in is hotter than its temperature setting. When the water falls below this temperature, the home's water heater makes up the difference. High-temperature solar water heaters provide energy-efficient hot water and hot-water heat for large commercial and industrial facilities.

Individual water heaters are the most common application for solar thermal energy. In the EU, more than 85% of the square meters of glazed solar collectors were used for heating water. Systems for heating domestic hot water and swimming pool heating have been on the market for over 20 years and are considered mature technologies in the OECD.

Other uses of solar thermal energy include space heating and solar cooking. Solar cookstoves have been promoted in India and Nepal with varying success. In 1998, only some 450,000 solar cookers were sold in India, many fewer than improved chulhas (bioenergy cookstoves).[50] It is unlikely that solar cookstoves will penetrate the market in developing countries over the next two decades.

The main barrier to implementing solar thermal energy on a large scale is cost, particularly the high up-front cost of equipment to collect and store solar energy. As is the case with most forms of renewable energy, environmental benefits are not reflected in costs and so they appear more expensive than conventional fuels. Solar thermal heating, however, produces no emissions during operation, although small levels of emissions are associated with the manufacture and installation of components and systems. Other barriers include the need for large collecting areas for large amounts of energy and intermittence.

Passive Solar

Passive solar designs optimise the use of solar energy to provide heating, cooling and lighting for buildings with little or no mechanical assistance. When passive solar designs are used, buildings are oriented in a

50. Jagadeesh, Dr. A. (2000).

way that they can take full advantage of the available solar energy. The most common features of passive solar heating are direct solar gain, thermal mass, and sunspaces. Direct solar gain involves the use of large areas of south facing windows. Thermal mass refers to materials such as masonry and water that can store heat energy for extended time and can prevent rapid temperature fluctuations. In sunspaces, glazing allows solar radiation to enter an accessible but isolated space on the south side of the building.

The two most common methods of passive solar cooling are the use of vegetation and natural ventilation. Painting buildings a light colour to reflect sunlight and keep them cool is also considered to be a passive solar construction technique.

Daylighting is the use of sunlight to replace electric lighting in a building. Windows provide light for the perimeter of buildings while atria, light-shelves and light-pipes, can transmit daylight into the interior of buildings.

Passive solar energy has the potential to supply a large proportion of the energy needs for a properly designed building. Recent advances in technology and building materials have greatly expanded the potential for passive solar energy.

Ocean Energy Supply Prospects

Ocean energy exists in two basic forms: the mechanical energy in waves and tides and thermal energy absorbed by the ocean's waters. The mechanical energy contained in waves is a function of the amount of water displaced from the mean sea level and the orbital velocity of the water particles in the waves. The energy transferred depends on the wind speed, the distance over which it interacts with the water and the duration of time for which it blows. It is estimated that the total power of waves breaking on the world's coastlines is on the order of 2,000 to 3,000 GW.[51]

Tides arise from the gravitational pull of the sun, the moon, and the earth's rotation. The energy of the tides is derived from the kinetic energy of water moving from a higher to a lower elevation. A dam is typically used to convert tidal energy into electricity by forcing the water through turbines, activating a generator.

51. Energy Efficiency and Renewable Energy Network, US DOE (www.eren.doe.gov)

Oceans cover more than 70% of earth's surface making them the world's largest solar collectors. Ocean thermal energy conversion makes use of the naturally occurring temperature difference between warm water on the surface and cold water at depths of about 1,000 m. The minimum difference in temperature is usually 20°C. Such differences are found in tropical and sub-tropical areas, making them favourable for the development of ocean thermal technology.

This form of energy is costly and is not likely to be widely commercialised by 2020. However, it will remain a promising option for electricity generation in the long term.

CHAPTER 6
GLOBAL URANIUM SUPPLY OUTLOOK

Summary

The needs of nuclear power generation are currently met by primary production of uranium and by stockpiles and inventories

- Roughly 60% of global demand for nuclear power is met from primary uranium production while the rest is derived from stockpiles and inventories of various types. But known reserves and uranium from secondary sources guarantee a secure supply over the next twenty years.
- Uranium costs account for only 3% to 5% of total generation costs.

Future growth in nuclear power is likely to occur in Asia, but there are signs of renewed interest in some OECD countries

- The share of nuclear power in the global electricity mix was 17% in 1999. Most future growth in nuclear power is likely to occur in Asia. Together, Japan, China and South Korea are likely to account for over half of cumulative additions to nuclear capacity in the period to 2020. Over the same period, some 30% of existing plants in OECD countries may be retired. But efforts to combat climate change could lead to higher nuclear capacity in 2020 than anticipated. The possibility of shortfalls in electricity generating capacity has renewed interest in nuclear power in some OECD countries.

Uranium reserves are abundant and concentrated largely in OECD countries

- At the current rate of use, known uranium resources are equivalent to some 250 years of current consumption, at extraction costs of less than $130 per kilogram. Australia, the United States and Canada account for over 35% of world resources, and they are recoverable at costs less than $130 per kilogram. After Australia, Kazakhstan has the second-largest uranium resources in the world, some 15% of the world total in 1999. OECD countries hold nearly 45% of known conventional resources.

Uranium production is likely to rise in the medium term

- Low prices over the last few years have meant that only low-cost uranium deposits have been mined. Uranium production in the near term will come from more efficient, lower-cost producers. Canada and Australia will be the largest primary producers. OECD countries are expected to account for over 60% of primary production in 2020. There remains considerable uncertainty about future production in the countries of the former Soviet Union. They have ample resources with which to expand output. The problem is securing the funds for significant capital investments.

Secondary sources of uranium will continue to be important

- The proportion of world uranium requirements met by secondary supplies, which include inventories, stockpiles and recycled materials of various types, has grown in recent years. These sources will play an important role in meeting reactor requirements over the next twenty years. Additional supplies on the market will include reprocessed fuel and residual uranium extracted from enrichment tails.

There is considerable uncertainty about secondary supplies

- Much uncertainty is due to the amount of defence-related uranium that may eventually reach the commercial market. Low-enriched uranium blended from highly-enriched uranium (HEU) from Russian warheads will help supply the market over the next several years. The long-term sustainability of Russian exports of HEU, natural uranium and re-enriched tails, however, is questionable. While more is known about Western uranium inventories, information is limited on inventories in Russia and in China.

Uranium prices will probably remain modest in the medium term...

- Uranium prices fell throughout most of the 1990s, largely as a result of the sale of secondary supplies. The availability of these supplies has meant that the global imbalance between production and consumption of primary uranium has had little effect on prices. There will be little upward pressure on uranium prices over the next decade. The fact that market prices have been kept at artificially low levels has given producers little incentive to undertake major exploration.

...but they may rise over the longer term as secondary supplies are depleted

- Supplies of secondary uranium released as a result of the end of the Cold War are expected to be depleted in 15 to 25 years. Commercial inventories are similarly projected to drop by 2020. As secondary supplies are drawn down, market prices will probably rise to reflect production costs. Because of the long lead time between the discovery and production of uranium, ten to fifteen years in most cases, producers must be assured that prices will remain high enough to support exploration and development expenses.

Overview of Uranium Market Trends

Demand for Nuclear Power Generation

Nuclear power provided 2,393 TWh of electricity in 1997, or 17% of global electricity output. Today, 438 commercial nuclear units operate in 31 countries with an installed capacity of 352 GW, about 11% of world electricity-generating capacity. Nuclear power was introduced in the 1950s and gained momentum after the oil shocks of the 1970s, when many countries regarded it as a stable and economic energy source that would ensure security of supply. Annual capacity additions averaged around 12 GW in the 1970s and 18 GW in the 1980s. Growth slowed in the 1990s, to 2.5 GW per year, primarily because lower fossil-fuel prices and lower up-front capital requirements made generation from coal and gas more attractive. Increasing public concern about nuclear safety was also a factor, particularly after the Chernobyl accident in 1986.

In the *WEO 2000* Reference Scenario, new nuclear capacity to be built up to 2020 amounts to a little over 100 GW. Some 135 GW of existing nuclear capacity will be retired, and the projected share of nuclear power in the global electricity mix will drop to 9%.

Box 6.1: **Recent Initiatives in Nuclear Power in OECD Countries**

Although nuclear capacity additions in the OECD are expected to be limited in Europe and to be zero in North America, renewed interest in nuclear power in some OECD countries has cast some uncertainty over these projections. The Generation IV International Forum, involving nine countries, Argentina, Brazil, Canada, France, Japan, South Korea, South Africa, the UK and the US, commenced in January 2000, with two objectives: to increase multilateral co-operation in planning for acceptable nuclear energy systems and to develop a framework for research and development of these systems. In the US, successful implementation of the Nuclear Energy Research Initiative projects could support higher-than-expected cumulative additions to capacity there.[1]

Expected output from nuclear power plants is set to decline more slowly than installed capacity because nuclear plants will operate at higher capacity factors, rising from 78% in 1997 to 84% by 2020. This trend is already confirmed in several OECD countries, where electricity-market reforms have encouraged improved performance to reduce costs. Owners of nuclear plants that do well in competitive electricity markets will seek to operate them longer. Table 6.1 shows details of nuclear capacity by region. OECD countries currently account for more than four-fifths of nuclear electricity production. Nuclear provides nearly a quarter of the OECD's electricity output and is the second largest source of electricity after coal. Retirements expected from now to 2020 are about 30% of existing plants. New construction in the OECD will be limited for two reasons. First, because nuclear faces strong competition from fossil fuels, especially from combined-cycle gas turbines. High capital costs are the most important economic factor weakening the prospects for new nuclear power. Second, because a large number of countries have phased out, or plan to phase out, nuclear power. Belgium, Germany, the Netherlands and Sweden have made political decisions to phase out the use of nuclear power.

1. More information on the Generation IV International Forum and on initiatives in the US can be obtained from: http://neri.ne.doe.gov and http://gen-iv.ne.doe.gov.

Most of the future growth in nuclear power will occur in Asia. South Korea is expected to account for over 60% of new capacity in East Asia, and Taiwan for another 30%. In South Asia, India is expected to add over 4 GW of nuclear capacity, while Pakistan will add less than 1 GW. Nuclear electricity production in the developing countries will grow by a factor of 2.5, but its share in electricity generation will stay at about 4%. Nuclear capacity in the transition economies is expected to decline. These countries have several nuclear reactors under construction, but the completion depends on their finding necessary funds.

Table 6.1: **Outlook for Nuclear Capacity by Region** (GW)

	1997	*2010*	*2020*	*1997-2020*	
				Additions	*Retirements*
OECD Europe	131	125	97	4	38
OECD North America	112	95	68	0	46
OECD Pacific	44	57	67	24	0
OECD	**286**	**277**	**232**	**28**	**84**
Transition Economies	**42**	**40**	**28**	**34**	**48**
Africa	2	2	2	0	0
China	2	11	20	18	0
East Asia*	15	27	29	16	2
Latin America	3	4	4	1	0
Middle East	0	1	1	1	0
South Asia	2	4	7	5	1
Developing Countries	**24**	**49**	**62**	**41**	**3**
World	**352**	**366**	**323**	**103**	**135**

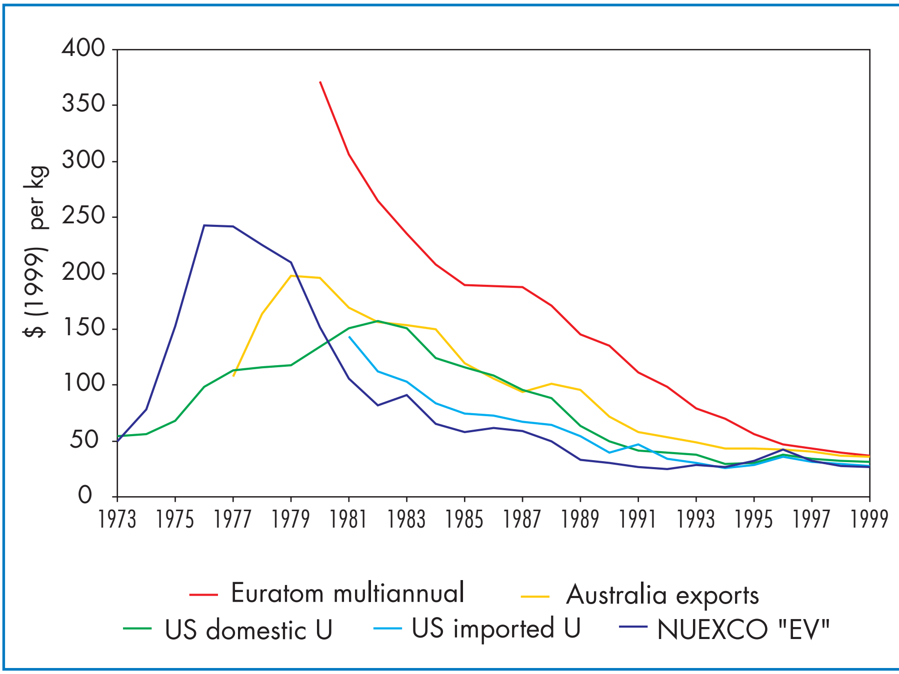
* Although South Korea is an OECD member, it was included in the East Asian grouping in the *WEO 2000* South Korea accounts for some 10 GW of cumulative additions to nuclear capacity in East Asia.
Source: IEA (2000).

Uranium Demand and Supply

Roughly 60% of global demand is met from primary uranium production while the rest is derived from stockpiles and inventories of various types. Global demand for uranium was estimated at 64,000 tonnes in 2000.[2] This demand was met by primary production, commercial inventory drawdowns, re-enrichment of depleted uranium (tails), reprocessed uranium, mixed-oxide (MOX) fuel[3] and highly enriched uranium (HEU).

Figure 6.1 indicates the downward pressure on uranium market prices since the late 1970s and early 1980s. This trend reflects the lower-than-expected global expansion of nuclear power and the resulting excess of supply. The pressure was exacerbated after 1987 largely by the sale of secondary uranium supplies.

Figure 6.1: **Real Uranium Prices in the OECD, 1973 to 1999**



Source: IEA (2001).

Until the late 1980s, the uranium market, except in Central and Eastern Europe and the former Soviet Union, was characterised by oversupply. Spot prices dropped in 1994 to their lowest point in 20 years. Prices recovered somewhat in the mid-1990s. However, this trend was

2. NEA/IAEA (2000).
3. MOX fuel is a mix of uranium and plutonium oxides.

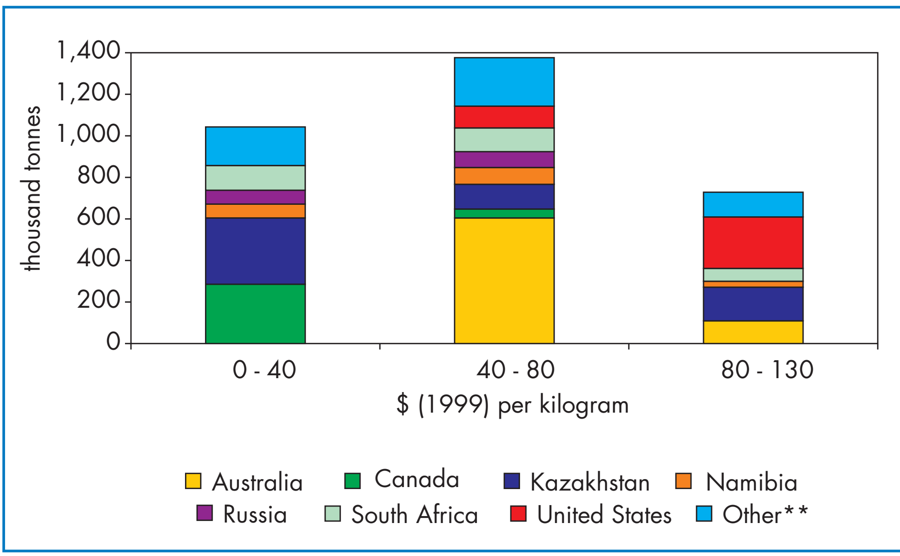
short-lived and was reversed by 1996. Prices have continued to decline gradually over the past four years. Real uranium prices in the OECD were roughly $31 per kilogram of uranium in 1999.

Key Factors Affecting Uranium Supply

Resources and Costs of Recovery

In 1999, known conventional uranium resources (KCR) recoverable for less than $130 per kilogram amounted to some 4 million tonnes. KCR consist of reasonably assured resources (RAR) and estimated additional resource category I (EAR-I).[4] The OECD's Nuclear Energy Agency and

Figure 6.2: **World Reasonably Assured Uranium Reserves*, by Cost of Recovery, as of 1 January 1999**



*The totals in each column refer to the NEA/IAEA's unadjusted resource estimates. Some of the resources included in the $40-to-$80 category, including resource estimates for Australia and the US, are recoverable at costs less than $80, but the countries did not specify whether they could be recovered at less than $40 or between $40 and $80.
**The "Other" category includes Argentina, Brazil, Denmark, Mongolia, Niger, Ukraine, Uzbekistan and countries with estimated resources under 10,000 tonnes.
Source: NEA/IAEA (2000).

4. RAR refers to uranium that occurs in known deposits and can be recovered with current technology. EAR refers to uranium that is inferred to occur, based on geological evidence, but where specific evidence concerning the characteristics of the deposit is insufficient to classify them as RAR. (NEA/IAEA, 2000)

the International Atomic Energy Agency classify reserves by cost of recovery, ranging from $40 per kilogram of uranium (kgU) to $130 per kgU. The cost of recovery depends on the quality of the resource and on mine-operating costs.

OECD countries have estimated known resources of 1.3 million tonnes, recoverable at a cost of less than $80 per kilogram of uranium. In Canada all the reasonably assured resources are recoverable at costs less that $80/kgU, while more than two-thirds of the uranium in the US will cost more than $80/kgU to recover. Most of Australia's resources are recoverable at costs less than $80/kgU. OECD countries have some 43% of estimated world resources recoverable at a cost of $130/kgU or less.

If resources are defined as uranium available at less than $130/kgU, world uranium resources are over 15 million tonnes, equivalent to more than 250 years of current consumption. This estimate does not include uranium stockpiles, reprocessing of fuel from existing reactors or fuel produced in breeder reactors. If these secondary supplies were included, uranium supplies could be extended much beyond 250 years.

Table 6.2: **Countries with the Largest Known Conventional Resources**
(thousand tonnes of uranium, as of 1 January 1999)

	Reasonably assured resources	**Estimated additional resources - category I**
Australia	716	194
Kazakhstan	599	259
United States	355	n.a.
Canada	326	107
South Africa	293	76
Namibia	181	108
Brazil	162	100
Russia	141	37
Uzbekistan	83	47
Ukraine	81	50

Note: Recoverable at costs less than $130/kgU.
Source: NEA/IAEA (2000).

Exploration

Total global expenditure on domestic uranium exploration has fallen over the past few years. The few increases have been concentrated in Canada, Australia, the US, Russia and India. Twenty-one countries were active in uranium exploration in 1998, with expenditures of $131.8 million. Canada and the US accounted for nearly half of total global expenditures. Expenditures on domestic exploration were some ten times higher on a global basis than expenditures for exploration abroad.

France accounted for almost one-half of all non-domestic exploration expenditures in 1998. The US, Canada and Japan accounted for most of the remainder. While Japan has no domestic exploration, Japanese companies are active in exploring Canada, Australia, the US, Niger and Zimbabwe.

Primary Uranium Production and Costs

Uranium is produced by conventional techniques, 40% by open pit mining, 33% by underground mining and the rest through modern techniques, including *in situ* leaching (ISL), phosphate by-product recovery and heap leaching.[5] ISL production is only suitable for sandstone-

Table 6.3: **Uranium Production**
(thousand tonnes of uranium)

	1999	*Total to 1999*
Canada	8.2	330
Australia	6	84
Niger	2.9	79
Namibia	2.7	70
Russia	2	111
Uzbekistan	2.1	94
United States	1.8	352
Kazakhstan	1.4	86
OECD	**17.3**	**1,071**
World	**31.1**	**n.a.**

Source: Data for 1999 from Uranium Institute (2000). Historical data from NEA/IAEA (2000). Total world production to 1999 is not available due to insufficient information.

5. Uranium Institute (2000).

type deposits. It accounted for some 17% of world production in 1999. The use of conventional techniques is likely to increase in the future, particularly underground mining. Increases in the use of ISL technology will depend on the viability of planned new projects in the US, Australia, China, Kazakhstan, Russia and Uzbekistan.

Global production of primary uranium declined from 1985 to 1995. Higher prices in the mid-1990s brought three years of production increases, but production fell again, by 5%, in 1998. World production declined by a further 8% in 1999 to some 31,100 tonnes. Low uranium prices over the last few years have meant that only low-cost deposits have been mined. New projects are expected to focus on unconformity-type deposits and *in-situ* leaching of sandstone-type deposits. Unconformity-type deposits have a higher ore grade than average uranium. The largest high-grade deposits are located in Canada, including McArthur River and Cigar Lake. Production from sandstone deposits is the basis of the uranium industries in Kazakhstan, Niger, the US and Uzbekistan.

Mining uranium is similar in many ways to mining other minerals, but it costs more because of safety factors. Time-consuming and expensive environmental reviews are generally required before new mines can open. Lead times to bring major projects into operation are in the order of ten to fifteen years from discovery to the start of production.[6]

Uranium was mined in 22 countries in 1999. OECD countries accounted for 56% of global production, equivalent to 17,300 tonnes. Canada and Australia were the largest producers, accounting for over 80% of total OECD production and nearly half of world primary production. In Canada, the high-grade McArthur River deposit began operation in 1999, and production was 5,080 tonnes in 2000. The mine is scheduled to produce over 8,000 tonnes annually by 2002. Australia's production potential increased in 1996 when the government's "three-mines policy" was rescinded. Three new uranium projects, Beverly, Honeymoon and Jabiluka, are currently under development, with a total production capacity of over 2,100 tonnes.[7] The US is another large producer, although many American mills are now on standby status. Production in the US fell from a high of 2,432 tonnes in 1996 to just over 1,800 tonnes in 1999.[8] US production is dominated by ISL operations located in the Wyoming Basins.

6. IAEA (2001).
7. IEAE (2001).
8. Uranium Institute (2000).

Smaller OECD producers include France, which produced less than 500 tonnes in 1999. France, Spain, Germany, Hungary and the Czech Republic have historically produced uranium to meet domestic reactor requirements. National programmes are increasingly being shutdown, however, and countries are turning to the international market to meet their uranium demand requirements. Spain ceased production in 2000. France will shut down uranium production by the end of 2001, while the Czech Republic plans to stop production by 2003.[9]

The four uranium-producing countries of the FSU, Russia, Uzbekistan, Kazakhstan and Ukraine, contributed nearly 20% of global production in 1999. Russia and Ukraine have nuclear energy programmes and much of their production is for domestic use. Production in Kazakhstan and Uzbekistan is now limited to *in situ* leaching operations. Uranium is an important source of hard currency for FSU countries; so they are likely to continue to produce uranium at current rates or even increase production in the future.

Four African countries, Niger, Namibia, South Africa and Gabon, contributed over 22% of world production in 1999. Namibia and Niger each accounted for 9% of global production in 1999. Argentina was the only Latin American uranium producer in 1999. Brazil planned to commence production in 2000, but its reserves are low-grade, and its operating costs are high.

In China, India and Pakistan uranium is produced entirely for domestic reactor requirements. In these countries, reserves tend to be low grade, and widespread commercial exploitation of them is unlikely in current market conditions. Western companies are working in Mongolia, and production there is expected to be over 1,000 tonnes in the very near future.

Secondary Supply Sources

In 2000, secondary uranium sources, which include inventories, stockpiles and recycled materials of various types, provided some 40% of world reactor requirements. Uranium inventories are owned by utilities, fuel-cycle companies and government bodies. Uranium supplies are relatively cheap to store. Inventories are held for a variety of reasons, the most important being: to enhance security of the nuclear power supply; to guarantee delivery schedules; and to hedge against variations in the price of uranium.

9. IAEA (2001).

The Uranium Institute[10] has evaluated inventories, using both a top-down and a bottom-up approach. Excluding military stockpiles and including inventories held by governments, the top-down approach produced an estimate of 215,000 tonnes of uranium worldwide. The top-down approach deducted cumulative consumption from cumulative production since 1945. Russia and the United States are the only two countries whose governments still have significant inventories.

The bottom-up approach was built from available figures on the inventories of individual countries or companies. Preliminary results of the survey indicate a Western inventory level of between 140,000 and 160,000 tonnes of uranium. The Uranium Institute estimates that the Russian inventory at end-1997 was some 58,000 tonnes of largely low-enriched uranium.

Disarmament agreements between the FSU and the US rendered large quantities of high-enriched uranium (HEU) and weapons-grade plutonium surplus to military requirements. In March 1995, 174 tonnes of HEU was declared surplus by the US government. The US Department of Energy plans to use some 60% of this as reactor fuel in the next 10 years or so.[11] The United States also has some 38 tonnes of military plutonium, equivalent to some 8,500 tonnes of natural uranium. There are plans to use the plutonium in mixed-oxide (MOX) fuel for reactors. The FSU is estimated to have produced some 1,400 tonnes of HEU, about one-third of which is being delivered to the United States in low-enriched form, Another 10% has been consumed domestically by the FSU successor states. Thus, there may be some 700 tonnes of HEU left in the FSU. Russia controls some 150 tonnes of military plutonium, equivalent to some 31,500 tonnes of uranium. Russia plans to use this material in its reactor programme, but has not yet done so.

Recycling of recovered plutonium in MOX fuel, and to a lesser extent reprocessing uranium, are common practices in some countries. This technology improves the overall efficiency of the fuel cycle but the quantities involved are rather small. There are five plants for the production of MOX fuel for light water reactors in the OECD, with total production of about 300 tonnes per year. In 1999, this represented 5% of

10. In early 2001, the Uranium Institute changed its name to the World Nuclear Association.
11. Uranium Institute (2000).

annual nuclear fuel requirements in the OECD. MOX fuel could, however, replace some 5,000 tonnes of uranium by 2010.[12]

There are also large stockpiles of depleted uranium, known as "enrichment tails". Depleted uranium is a by-product of the uranium enrichment process. In 2000, world stocks of depleted uranium were estimated at some 1.2 million tonnes, with some 80% held in the US and Russia.[13] The economics of using depleted uranium depend on its U-235 content and on the cost of enrichment services. The key factor driving the future supply of depleted uranium will be the enrichment needs of nuclear-generating capacity worldwide. Current demand for primary tails is some 5,700 tonnes per year. The NEA estimates that this level could be reduced by up to 20% due to displacement by MOX fuel and down-blended HEU over the next decade.[14] Although quantities are uncertain, potential Russian exports of re-enriched uranium from depleted uranium stockpiles could range from 5,000 to 9,000 tonnes per year.[15]

Government Policies

Political decisions will strongly affect the market for secondary uranium over the next two decades. These include: the conversion of weapons-grade highly-enriched uranium (HEU) to civilian use; US and EU restrictions on the sale of uranium produced in countries of the FSU; and the sale of US government stockpiles of uranium. The restrictions imposed by the US DOE and the Euratom Supply Agency (Euratom) are very severe.

In order to ensure regular and reliable supply, EU countries with nuclear programs avoid over-dependence on any single source of uranium supply. Euratom recommends that EU users not depend on the FSU for more than a quarter of their natural uranium needs or for more than a fifth of their enrichment needs. To avoid supply disruption, EU users are encouraged to maintain a portfolio of diversified, long-term contracts with primary producers and to limit reliance on secondary sources.

Japan is the third largest user of nuclear power in the world, but produces no uranium domestically. Currently, Japan ensures a stable supply of uranium through long-term purchase contracts with overseas

12. NEA/IAEA (2000).
13. NEA/IAEA (2001).
14. Significant increases in the use of depleted uranium could arise if fast breeder reactors become more widely adopted. (NEA/IAEA, 2001)
15. Uranium Institute (2000).

uranium suppliers and through direct participation in foreign mining countries. The Japan Nuclear Cycle Development Institute has access to some 40,000 tonnes of uranium in mining interests in Canada, Australia, the US, Niger and Zimbabwe.[16] Uranium requirements in South Korea are met through long-term contracts with suppliers in Canada, Australia, France and the US.

While the US and France both produce uranium, domestic production provided less than 10% of their power-generation needs in 1998. France's policy towards uranium procurement is one of supply diversification. French mining operators participate in uranium exploration outside France and also purchase uranium, under short or long-term contracts, from mines in which they have shareholdings and from mines operated by third parties. The United States has some 62,000 tonnes of natural uranium in stockpiles.

Uranium Supply Prospects to 2020

Table 6.4 compares the expected requirements for uranium with two estimates for uranium supply in 2020. The Uranium Institute estimates[17] indicate that the primary production of uranium may cover nearly 80% of global uranium demand in 2020.[18] The estimate for potential production in the transition economies is based on the current economic situation and on current restrictions on sales to the West. If joint ventures with Western companies prove fruitful and restrictions are eased, FSU production could increase significantly. According to the Uranium Institute, Australia and Canada will account for over half of world uranium production capacity in 2020. Production capacity is expected to be 17,600 tonnes in Canada and over 4,000 tonnes in the US.

16. NEA/IAEA (2000).
17. (Uranium Institute, 1998). The supply figures are based on the UI's reference case, which assumes an average capacity utilisation of current and planned mines of 86% over the period to 2020. "Current capacity" refers to operating mines which are expected to continue to operate in the future. "Planned capacity" refers to mines which are at an advanced stage and for which a start-up date is definite. The estimate for uranium supply in 2020 does not include "potential capacity" because there is considerable uncertainty attached to the start-up date of these mines.
18. The balance in supply in Table 6.4 will be met by secondary sources of uranium.

The International Atomic Energy Agency (IAEA) has made projections for uranium supply to 2050. Its projections to 2020 are indicated in Table 6.4. The IAEA assumes that the uranium production industry will gradually adopt market-based economic principles. Expected supply in 2020 is higher than the Uranium Institute's estimates because expansion plans, which are likely to be implemented, are included in the projections.

Table 6.4: **Primary Uranium Demand and Supply in 2020**
(tonnes of uranium)

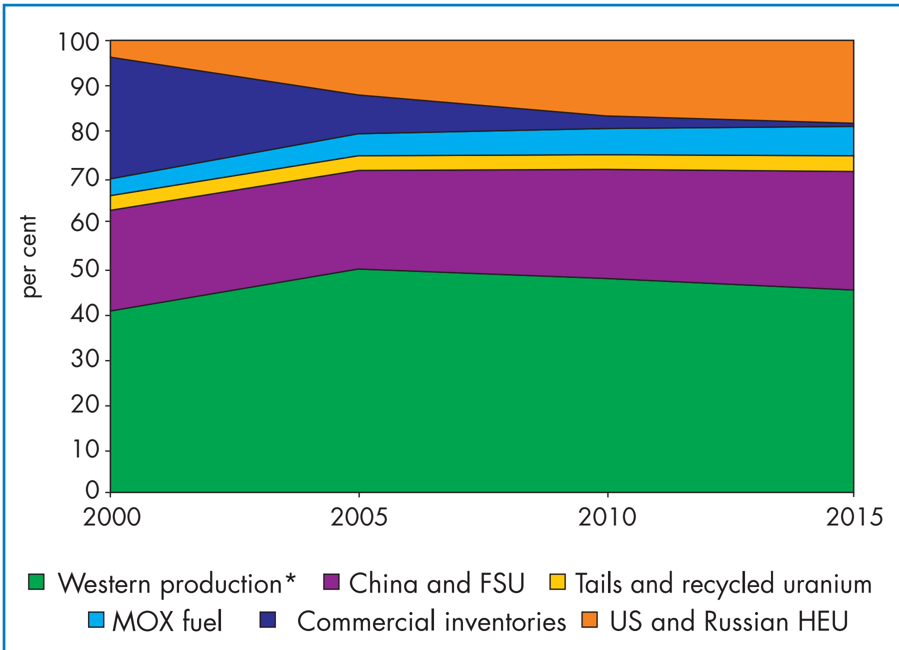
	Demand in 2020	**Supply in 2020**	
	WEO 2000* Requirements	**Uranium Institute****	**International Atomic Energy Agency**
OECD Europe	17,654	1,049	-
OECD North America	12,376	18,619	20,700
OECD Pacific	12,194	9,193	21,600
OECD	**42,224**	**28,862**	**-**
Transition economies	**5,096**	**5,676**	**11,200**
Africa	364	8,213	5,100
China	3,640	860	1,380
East Asia	5,278	1,290	-
Latin America	728	129	-
Middle East	182	0	-
South Asia	1,274	241	-
Developing countries	**11,284**	**10,733**	**-**
World	**58,786**	**45,270**	**65,400*****

* World nuclear generation capacity in 2020 is expected to be 323 GW (Table 6.1). The conversion factor is from the Uranium Institute.
** Anticipated uranium production capacity from current and planned mines, assuming 86% capacity utilisation (Uranium Institute, 1998, p.105).
*** Includes 6,800 tonnes from other Western producers.

The IAEA assumes that increases in production will only take place in those countries where they can be economically justified. Otherwise, countries will purchase uranium on the open market. In its middle-demand scenario, the IAEA projects that uranium demand will be some 83,000 tonnes in 2020. Of this, 65,400 tonnes is expected to be filled from primary production, with resources recoverable at costs of between $34 and $52 (at 2000 rates) per kg. The study suggests that spot market prices may not rise above $52 before 2020.

An analysis of uranium supply over the next 15 years was also undertaken by the Energy Information Administration in the US.[19] Global uranium requirements are projected to equal some 54,000 tonnes in 2015. As the quantity of uranium supplied from inventories held by utilities and commercial suppliers is reduced over the next several years, more Western production will be required to meet demand. By the middle of the next decade, Western production is expected to meet nearly 60% of Western

Figure 6.3: **Projected Shares of Primary and Secondary Uranium Supply**



*Includes US, Canada, Australia, Africa, Western Europe, Latin America, Mongolia, India and Pakistan.
Source: *Projections of US Uranium Spot-Market Price, EIA.*

19. http://www.eia.doe.gov/cneaf/nuclear/special/uranproj.html.

uranium requirements. To elicit additional production, the EIA study projects that the spot-market uranium price will need to rise by about 30% from 1999 to 2015. Canada and Australia are expected to be the principal uranium producers throughout the period to 2015. The EIA projects that declining inventories will be offset by increased use of Russian and US highly enriched uranium.

The *WEO 2000* examined an alternative case for nuclear power generation in OECD countries over the period to 2020. This case was based on the assumption that efforts to reduce CO_2 emissions could lead to higher nuclear capacity. Greater emphasis on energy security, combined with the fact that nuclear power is little affected by changes in fossil-fuel prices, would tend to support the growth of nuclear power. In this case, OECD requirements would rise to over 56,000 tonnes of uranium in 2020, increasing world requirements by some 14,000 tonnes, or some 24%. This could increase the draw on world inventories, but upward price pressure will not be severe given the availability of uranium resources in Western countries, primarily in Australia and Canada.

Box 6.3: **Uncertainties on Supply Prospects**

Determining the global supply of uranium over the next two decades is surrounded with uncertainty for the following reasons.

The size of accumulated stockpiles of both natural and enriched uranium is not accurately known. The IAEA considers two categories of natural and low enriched uranium, a commercial inventory held by Western countries and the inventory held by Russia. The Western inventory drawdown is linked to future demand requirements. In its middle-demand case, the IAEA projects that, by 2016, inventories will be drawn down at a faster rate than they are maintained by producers. Although uranium production in the FSU is known to have exceeded civilian and military requirements over the past 40 years, there is little information on the size of the remaining stockpiles.

Non-traditional suppliers may increase their production and exports, including China, Kazakhstan, Russian and Uzbekistan. China's current and future uranium production is uncertain, partly because of Chinese laws prohibiting release of resource estimates and annual production totals. Although most of China's uranium production is consumed domestically, small sales were made to satisfy sales commitments from the 1980s. China is increasingly faced with high production costs and lack of known resources as it struggles to satisfy increasing demand from its civilian nuclear power industry. A near-term increase in production in Kazakhstan is supported by two joint ventures with Western companies. These countries could each add between 700 and 800 tonnes of uranium to current production capability by 2005. In Russia, pilot tests using ISL technology have been ongoing in the Trans-Ural region, with production scheduled to start in 2001 to 2003. Exploration drilling has been completed in two other areas with ISL potential, Western Siberia and Bitim. Part of Uzbekistan's increase in production between 2000 and 2005 is predicated on successful implementation of a joint venture with a Western company to develop the ISL potential of the Sugraly deposit.

Surplus uranium and plutonium from US and Russian military programmes will enter the uranium market over the next few years. These supplies will displace natural uranium production, but the timing and size of annual releases of this military material is not certain. Contracts were signed in 1999 for 70% of the uranium content of Russian HEU to be marketed by three Western companies over the period to 2013. A Russian company will market the remainder.

Nuclear Fuel

Nuclear fuel must be specially processed and embedded in fuel assemblies before it can be used in power plants. The facilities for preparing nuclear fuel are themselves essential parts of the nuclear fuel supply chain, few of which are competitive. Many of the key facilities needed for producing nuclear fuel and for processing spent fuel are owned by governments and were developed either for specific nuclear power development programmes or for strategic or military purposes.

The main operating costs of nuclear plants are nuclear fuel, operations and maintenance and provisions for spent fuel management and disposal. The share of each component varies by plant type and by country. In contrast to fossil fuels, the cost of the raw commodity, uranium, is not the main determinant of generating costs. Uranium costs account for only 20 to 30% of nuclear fuel costs, which in turn account for only 15% of total generation costs.[20] The price of nuclear fuel is most dependent on the cost of nuclear fuel services: conversion, enrichment, fuel fabrication and final processing.

Table 6.5: **OECD and World Uranium Conversion Capacities for Production of Light Water Reactor and Advanced Gas-Cooled Reactor Fuel, 1999** (Yellowcake to Uranium Hexafluoride Only)

	Sites	**Capacity** (tonnes-per-year)
Canada	Blind River/Port Hope*	12,500
France	Malvesi/Pierrelatte**	14,000
Japan	Ningyo-Toge	120
United Kingdom	Springfields	6,000
United States	Metropolis works	12,700
OECD		**45,320**
Russia	Angarsk	18,700
Others	Brazil, South Africa	790
Non-OECD		**19,490**
World		**64,810**

* Capacity of Port Hope uranium hexafluoride production.
** Does not include 350 tonne-per-year capacity for conversion of reprocessed uranium.
Source: IEA (2001).

There are five uranium conversion plants and eight uranium enrichment plants in the OECD. France and the US account for over 50% of total production capacity in conversion, enrichment and fuel fabrication. Outside the OECD, Russia possesses over 95% of the world's remaining conversion and enrichment capacity.

At 1998 rates of nuclear electricity production, the OECD was self-sufficient in enrichment and fuel fabrication. Fuel fabrication capacity surpasses requirements in the Western world by 40%.[21] Existing capacity is more than sufficient to meet future requirements over the next two decades. Fuel fabrication facilities are more widely spread within the OECD than conversion and enrichment facilities. In 1999, fabrication facilities in the OECD consisted of some 9,400 tonnes heavy metal per year of light water reactor fuel, 3,650 tonnes heavy metal per year of Candu fuel and 1,460 tonnes heavy metal per year of Magnox and

20. These percentages depend on the discount rate used.
21. Uranium Institute (2000).

advanced gas-cooled reactor fuel.[22] Fabrication facilities are tailored closely to individual reactor designs, since fuel assemblies must meet the specific mechanical and physical constraints of individual reactor designs.

Box 6.4: **The Nuclear Fuel Cycle**

The nuclear fuel cycle refers to the *production of nuclear fuel*, *the recycling of used fuel* and *the disposal of radioactive waste*. Nuclear-fuel production begins with the mining of uranium ore. The ore is milled and chemically converted for use in enrichment plants. The chemically converted ore, or uranium hexafluoride, is enriched in uranium-235, and fuel is prepared from the enriched uranium.

Once the uranium fuel has been used in the reactor to generate electricity, it is removed and placed into temporary storage, either to go on to a disposal site or to be reprocessed. Reprocessing spent nuclear fuel, which involves extracting plutonium and uranium to be recycled, reduces the quantity of high-level waste per unit of generation. Reprocessing of spent fuels in Germany will end in 2005, while Japan's policy is eventually to reprocess all spent fuel. In the 1990s, there was a growing interest in the recycling of plutonium in mixed-oxide (MOX) fuel. MOX fuel is best suited for fast-breeder reactors, but at present no such reactors are in use and there is little likelihood that they will be used in the near future. MOX fuel can safely be used in conventional reactors, and there are 32 reactors worldwide licensed to use MOX fuel. Additional safety concerns about its use in existing plants have limited MOX fuel to 50% in these plants. Compared with the alternative of direct disposal of nuclear waste, reprocessing combined with the production of MOX fuel can reduce high-level waste production by roughly 50% to 85%.

Cost estimates vary for high-level waste disposal facilities and for programmes. In 1999, estimates for developing and constructing high-level waste disposal facilities varied from the lowest in Sweden, France and the UK, at less than $2 billion, to the highest in the US and Australia, at over $6 billion. Some of the main factors affecting cost are: regulatory limits on risks of public exposure to radioactivity; timing of waste disposal after plant operation; location of waste facilities in relation to the earth's surface and the physical characteristics of the site; and financial support to communities hosting waste sites. Disposal

22. IEA (2001).

costs are much lower for low-level waste than for high-level waste. Siting waste facilities has become increasingly difficult in most OECD countries, due to more stringent rules for their operation. In Finland, however, a Decision-in-Principle, ratified in May 2001, gave formal authorisation to build an encapsulation plant for spent nuclear fuel and underground final-disposal facilities. Construction is expected to commence in 2010. The EU has given formal approval for the disposal site. Outside the OECD, the Russian Duma voted in August 2001 to allow the import and storage of spent nuclear fuel. If President Putin signs the measure, and the Federation Council approves it, Russia could import some 20,000 tons of spent nuclear fuel over the next decade.

Table 6.6: **OECD and World Uranium Enrichment Capacities, 1999**

	Sites	**Technology**	**Capacity** (thousand separative work units* per year)
France	Pierrelatte	diffusion	10,800
Germany	Urenco Gronau	centrifuge	1,100
Japan	Rokkasho, Nignyo-Toge	centrifuge	950
Netherlands	Urenco Almelo	centrifuge	1,500
United Kingdom	Urenco Capenhurst	centrifuge	1,800
United States	Padecah, Portsmouth**	diffusion	19,200
OECD			**35,350**
Russia	Ekaterinbury, Tomsk-7, Krasnoyarsk-45, Angarsk	centrifuge	19,000
Others	Argentina, China, Pakistan, South Africa	various	725
Non-OECD			**19,725**
World			**55,075**

* In the OECD, some 4.3 separative work units are required for each tonne of uranium contained in light water reactor fuel.
** In May 2001, the Portsmouth diffusion plant discontinued operations.
Source: IEA (2001).

Conversion capacity within the OECD was below requirements in 1998, similar to the situation in uranium production. Most imports of uranium from countries of the FSU have already been converted to uranium hexafluoride. This tends to reduce the need for uranium conversion capacity within the OECD.

CHAPTER 7
THE ENERGY SUPPLY OUTLOOK BEYOND 2020

Summary

The long-term energy supply outlook depends critically on technology development and deployment

- Technology will affect the choice and cost of future energy systems, but the pace and direction of change is highly uncertain. The extent to which new technologies focus on low or zero carbon emissions, and the costs involved, are key uncertainties in the long term. Fossil fuel resources are more than adequate to meet energy demand well beyond 2020, but continued reliance on them may require the large-scale introduction of technologies to capture carbon.
- *Oil* production costs will be highly dependent on recovery rates and on the use of unconventional resources, which are likely to cost significantly more than conventional oil to exploit. The long-term supply outlook for *natural gas* depends largely on lowering the cost of long-distance transportation. In the *very* long-term – probably beyond 2050 – gas hydrates offer the prospect of a virtually limitless supply of gas, although the technology and costs of exploiting this resource are extremely uncertain. The long-term *coal* supply outlook depends largely on whether ways can be found to use coal in an environmentally acceptable way. Production costs may not be a constraint.
- Beyond 2020, the role of *renewable energy* in global energy supply is likely to become much more important. Environmental impact will be a key factor in determining which types of renewables grow most rapidly in different locations. The increasing need for new power-generation capacity will create real opportunities for renewable energy to penetrate the power sector. How rapidly it does so in the long term will depend on cost relative to competing technologies. Technological innovation will be needed to get costs down.

- The future of *nuclear power* is very uncertain. Some governments may seek to expand or introduce its use as a way of reducing carbon emissions or enhancing fuel diversification. But there will be countervailing pressures to abandon nuclear energy unless concerns over environmental impact and safety are met. Most of today's nuclear plants will reach the end of their life some time beyond 2020. Decisions about their replacement will be needed well in advance.

Cross-cutting technologies hold out the prospect of an environmentally benign energy supply

- A number of technologies under consideration or active development exploit energy from several different sources. Hydrogen-based fuel cells are the main focus of current research and development on cross-cutting supply technologies. These hold out the prospect of large-scale energy production with minimal environmental impact, the amount of carbon and other emissions depending on how the hydrogen is produced. Fossil fuels may provide the initial source of energy for hydrogen production for use in fuels cells. Much later, depending on how technology advances, hydrogen production may be based on electrolysis of water using nuclear or renewable energy. In that case, net carbon emissions could be negligible.
- Carbon sequestration – the separation of CO_2 from fuels at their point of production or flue-gases at their point of combustion and its storage in ocean or geological formations - could also have a profound impact on the long-term prospects for energy supply.

Governments will play an important role in encouraging technological progress

- Technological development and deployment are strongly influenced by government actions, including pricing and taxation policies and direct funding of R&D. Many governments have expressed their commitment to step up efforts to reduce CO_2 emissions. Such policies could be expected to have a major influence on future energy supply.
- Government policies aimed at reducing the risk of a supply disruption or promoting more efficient markets can also affect the supply outlook. Concerns over security of supply will grow as countries and regions become more dependent on fewer and fewer external supply sources or vulnerable transportation routes.

Regulatory and market reforms, which are expected to go further in the long term and cover a growing number of countries, could lead to important gains in efficiency, thereby lowering the cost of supply.

Introduction

The main purpose of this study is to consider the key issues that are likely to affect energy supply worldwide over the next twenty years. This Chapter goes beyond the time horizon of the supply analysis presented in Chapters 2 to 6 and discusses long-term developments for each of the individual primary energy sources - oil, gas, coal, renewables and uranium. It provides an assessment of the evolution of the resource base, the technological advances that could take place, how markets could develop and the impact on energy supply of government energy policies. It does not attempt to develop forecasts or scenarios, or to assess which supply options are likely to emerge as dominant in the long term. Rather, the emphasis is on providing insights into how the future could unfold for each fuel by looking at the whole spectrum of supply options. Uncertainty about the key driving factors of energy supply inevitably increases as the time horizon extends further into the future.

There are ample energy resources to support consumption in the longer term, but which reserves can be economically produced will depend on production costs and on the price that the fuel can be sold for. The downward trend in production costs through technological advances is likely to continue. But fossil-fuel prices could increase as the lowest-cost reserves are depleted and a small number of increasingly dominant oil-exporters seeks higher prices.

Technological developments will affect the choice and cost of future energy systems, but the pace and direction of change is highly uncertain. The extent to which those developments will focus on low or zero carbon-emitting technologies and the costs involved are key uncertainties. Technological development can be strongly influenced by governments, through pricing and taxation policies and direct funding of research and development.

Government policies can affect the supply outlook in other ways. Concerns over security of supply will grow as countries and regions become more dependent on fewer and fewer supply sources or transportation routes that are vulnerable to disruptions. Governments have an important role to play in reducing the risk of supply disruptions. Regulatory and market reforms, which are expected to go further and cover a growing number of countries, will also affect supply. Increased competition between different fuels and between different suppliers of the same fuel will tend to narrow the gap between production cost and market prices, reducing monopoly rents, encouraging greater efficiency and lowering the cost of supply.

Oil

The prospects for oil supply after 2020 will be influenced by technological, market and policy developments as well as by demand-side factors.

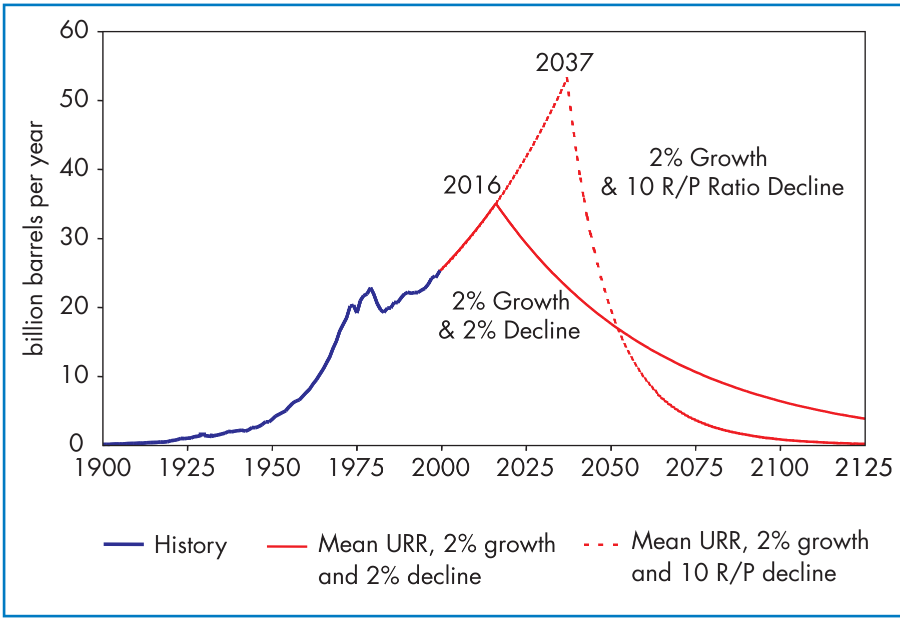
Resources and Technology

Long-term oil supply is limited by the amount of economically recoverable resources of both conventional and unconventional oil. The portion of the total oil originally in place that can be economically recovered depends upon the cost of recovery and the price that the oil can be sold for. Chapter 2 shows that technology can increase economically recoverable resources through reduction in the cost of extraction and consequent increase in the recovery factor, as well as through identification of additional oil reserves. The trend in cost reduction is expected to continue. The application of advanced oilfield technology in areas such as Russia and Iraq is likely to increase considerably the amount of economically recoverable reserves.

Analysis of the relationship between the size of conventional oil reserves and production indicates that the shape of the production curve after individual oilfields reach their peak is the key to determining the peak production year on a global basis. Figure 7.1, adapted from US DOE/EIA, shows that assuming an annual production growth rate of 2% and a decline rate of 2% results in a peak of production in 2016 based on a mean estimate of ultimate conventional oil resources of 3,003 billion barrels. This is compared to a scenario in which production increases at 2% per year (the EIA's projected average annual rate of global oil demand growth to 2020) until the ratio of reserves to production (R/P) falls to 10 (it is currently around 40), at which point production declines in a way that maintains a constant R/P ratio of 10.[1] In this case the peak year of production is 2,037.

1. The choice of R/P ratio is based upon data from the United States, which indicates that R/P ratio has been between 8 and 12 for the last 50 years.

Figure 7.1: **Annual Production Scenarios with 2% Growth Rate and Different Decline Rates**



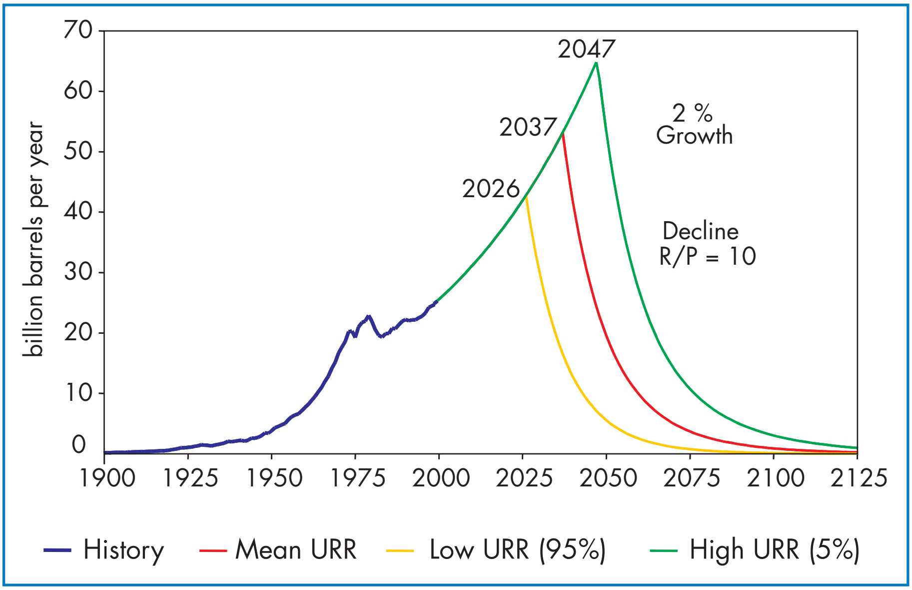
Note: URR is Ultimate Recoverable Resources. Mean URR used is 3,003 billion barrels. One decline rate is 2% per year, and the other uses an R/P ratio of 10 years.
Source: Hakes (2000).

Reserves are computed from resources using an algorithm that factors in annual finding and production rates. Figure 7.2 shows that increasing resources by 900 billion barrels delays the expected peak of production by 10 years, using the constant R/P ratio for modelling decline.

Ultimate recoverable resources have grown over time and are expected to continue to grow with improvements in upstream technology. The recovery factor depends upon the cost of oil extraction. For example, nearly all the oil can be recovered from tar sands, since the rock can be processed at ground level to extract the oil. Mining rock containing oil is not a cost-effective option at current oil prices for reserves that are found thousands of metres below the earth's surface. The technology exists to mine minerals deep in the earth's formation, like gold, but the price of oil is not high enough to justify using this technology.

The discussion of non-conventional oil resources in Chapter 2 indicates that the earth contains enormous volumes of extra-heavy oil and bitumen. The technology exists to extract them, but the cost is high

Figure 7.2: **Annual Production Scenarios with 2% Growth Rate and Different Resource Levels (Decline R/P = 10)**



Note: URR is Ultimate Recoverable Reserves. The mean URR is 3,003 billion barrels. The low URR (95% probability that resources are higher) is 2,248 billion barrels. The high URR (5% probability that resources are higher) is 3,896 billion barrels.
Source: Hakes (2000).

compared to that for conventional oil reserves. In addition, the cost of extracting oil from tar sands is dependent on the cost of the fuel used in the process.

Technology currently exists to increase the effective volume of liquid hydrocarbon reserves through the conversion of solid hydrocarbons (coal) and gaseous hydrocarbons into liquid hydrocarbons. Recent developments have reduced the cost of these processes. Gas-to-liquids (GTL) technology in particular can augment the supply of oil products based on natural gas that would otherwise be stranded at oil prices above $20/barrel. The economics of GTL projects may depend on the level of any penalties for carbon emissions, since the technology is energy-intensive.

Policy Considerations

Government policy, especially as it relates to security of oil supply, will influence the long-term development of oil reserves as well as their transportation to market. Governments in mature producing areas can extend the life of their oil industries through initiatives that stimulate efficiency and productivity. Fiscal policy can also be adjusted to encourage companies to invest in the development of less commercial fields or increase the recovery factor of older fields. Inter-governmental agreements can reduce the geo-political risks associated with oil supply projects and reduce the cost of capital for projects with marginal profitability.

Natural Gas

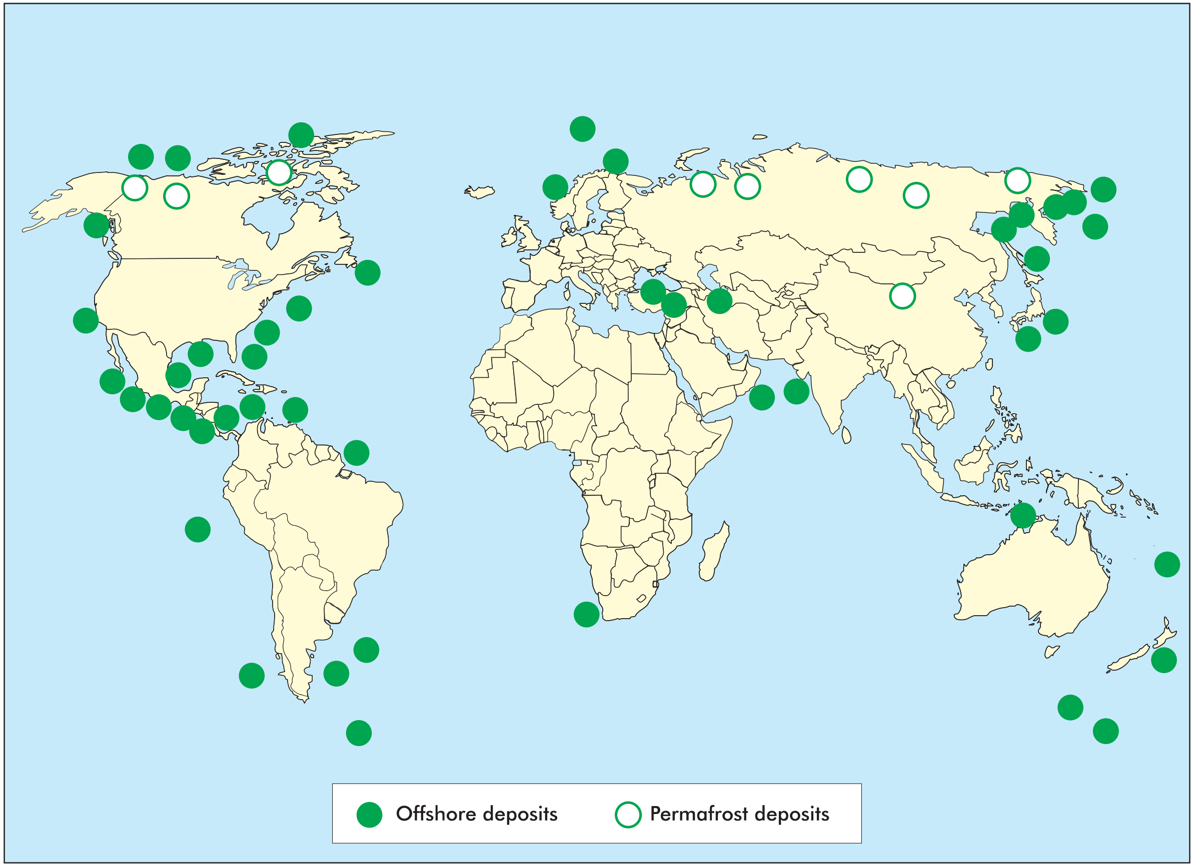
Resources and Technology

The long-term impact of technological advances on the way in which gas reserves are developed and transported could be very great. Estimates of conventional gas resources suggest that there will be ample resources to support the projected growth in supply until well beyond 2020. Nevertheless, the marginal cost of supply could increase sharply in the long run as the nearest-to-market and lowest-cost conventional resources, especially in large fields, are depleted. This may lead to greater emphasis on unconventional resources, such as coalbed methane, tight gas, ultra-deepwater resources and arctic resources. There is undoubtedly a huge potential for supplying gas from these sources, although development costs could be high. Trends in development costs will depend largely on successful research and development.

Gas Hydrates

Gas hydrates are another potential long-term source of natural gas. Natural gas hydrates are solid, crystalline ice-like substances composed of water, methane, and usually a small amount of other gases, with the gases trapped in the interstices of a water-ice lattice. They form under moderately high pressure and at temperatures near the freezing point of water. Hydrate deposits are found throughout the world on subsea continental shelves and slopes and in permafrost regions. Hydrates primarily occur at the base of the continental margins at depths exceeding 500 metres. They are generally located between 100 and 500 metres below the water-sediment interface. In Arctic areas, they occur at very shallow depths due to the very low mean surface temperatures in these regions. Very large accumulations have been identified in the last twenty years, particularly off the coasts of Japan, the east coast of the United States (Blake Ridge), British Columbia, New Zealand and New Caledonia (Figure 7.3).

Figure 7.3 : **Known and Inferred Occurences of Gas Hydrates**



Gas hydrates are the world's largest hydrocarbon reservoirs. If the technology is developed to exploit them economically and in an environmentally acceptable way, hydrate resources could meet any conceivable level of gas demand for centuries to come and would transform the fossil-fuel supply outlook.

Little is known so far about gas hydrate reservoir conditions and possible production methods. One of the most appealing aspects of this potential new gas source is that large deposits are located near the centres of high demand. Another major motivation for seeking to produce gas from hydrates is their high concentration of energy. A cubic metre of hydrate in a reservoir rock (with 30% porosity) may hold 50 cubic metres of gas, many times greater than can be stored in other gas sources at moderate reservoir depths.

World estimates for the amount of gas in gas hydrate deposits range from 14 to 34,000 tcm for permafrost areas and from 3,100 to 7,600,000 tcm for oceanic sediments. The oceanic sediments seem to hold the largest volumes of hydrates, but those resource estimates are the most uncertain. Median estimates of the amount of methane in worldwide gas-hydrate accumulations are about 21,000 tcm. This figure is over 100 times greater than the generally accepted value for conventional methane reserves. In 1995, the USGS estimated in-place US onshore and offshore gas-hydrates resource at 9,065 tcm (mean).

Methods for producing gas from hydrates on a commercial scale have yet to be developed. For this reason, gas hydrates must be considered a potential rather than a confirmed energy resource option. According to USGS models, gas hydrate development costs might be within the range $3 to $5/Mbtu, assuming the technology becomes available.[2] Production, if possible, is unlikely to be economic until well beyond 2020.

Transportation Technology

Further improvements and cost reductions in transporting gas to market are possible beyond 2020, although major technological breakthroughs appear unlikely given the current mature state of pipeline and LNG technology. The biggest opportunity for reducing the costs of pipeline transportation is probably through economies of scale, with the development of higher-capacity pipes operating at higher pressures. It has been suggested that natural gas could be transported by ship like LNG, but

2. EIA (1999).

in the form of hydrates.[3] The energy density of hydrates is about 170 times that of conventional natural gas, but is only a quarter that of LNG, so that much bigger carriers would be needed to transport the same amount of energy. However, hydrates can, in principle, be transported at atmospheric pressure and relatively mild temperatures (around -5ºC) compared to LNG, so that the overall capital and operating costs would probably be lower per Mbtu transported.

Gas-to-Liquids (GTL) Technology

There may be greater scope in the long term for advances in gas-to-liquids technology, including the development of higher-yielding catalysts and improved thermal efficiency of the various processes involved in converting natural gas feedstocks. GTL and/or similar gas-conversion technologies could revolutionise the gas industry by facilitating the development of reserves currently considered to be "stranded" by their small size and remoteness from markets. At the very least, GTL can be expected to limit crude oil producers' long-term ability to seek much higher oil prices in the long term, since higher oil prices could stimulate much faster development of the GTL industry and reduce the demand for crude oil.

Producers may consider various means of exploiting reserves, including some combination of LNG, GTL or gas-to-chemicals. Such tailored packages could render the development of more associated oil-and-gas fields economically viable.

Market Evolution

The global gas market in 2020 is likely to be more commoditised and integrated than it is today, as regional markets open up to competition and production and trade in gas grows. Commoditisation – a process in which gas is freely traded as a homogenous product – will be characterised by convergence between different markets:

- Regional gas markets will be brought together through physical supply links, particularly LNG, that will allow for more flexible patterns of supply.
- Gas, oil and coal markets will be linked through inter-fuel competition and the comparative economics of gas, coal and crude oil as sources of oil products.

3. See Nakicenovic (2000).

- Gas and electricity markets will converge through gas-fired power generation.

The development of competitive markets will provide opportunities for buyers and sellers of gas to exploit arbitrage opportunities between these different markets on the basis of market price signals. Gas markets will tend to become more like oil markets. Liberalisation will break down the rigid contractual link between oil and gas prices that is observed in most markets where gas-to-gas competition has yet to establish itself. But the price of gas will remain strongly influenced by the prices of other fuels that compete in end-use markets, both in the short and long term.

Access to finance and the timing of investment decisions will crucially determine the speed and extent to which gas and energy markets converge in these ways. Gas-supply projects will always be highly capital intensive, with long lead times. Supply bottlenecks, like those observed in recent years in parts of North America, can lead to imbalances between regional markets and upset normal price differentials for gas and between gas and oil.

Policy Considerations

Government policy considerations will continue to exert a major influence over gas supply trends in the longer term. Policy is likely to be driven increasingly by concerns over security of supply, as countries and regions become more dependent on distant supply sources or a small number of transportation routes. Regional economic and political groupings and national governments will seek to reduce the risk of short-term supply disruptions and promote investment in cross-border supply projects, among other ways through multilateral cooperation on trade and investment rules.

Coal

Coal resources are vast and widely distributed around the world. This gives coal a major advantage, from an energy-security perspective, over other fuels. However, as noted in Chapter 4, only some of these resources are economically recoverable using current technology. Nonetheless, using estimates of proven coal reserves (coal that is both technologically and economically recoverable), today's world reserve base represents more than 200 years of current production. The outlook for coal production and supply costs is subject to less uncertainty than are those for oil and gas.

Major changes are not expected in the medium term, although continued productivity gains should result in some further cost reductions. The biggest uncertainty for coal supply concerns demand, which in turn is heavily dependent on how coal-combustion technologies develop in response to environmental worries.

Cost and Market Developments

Mine-productivity improvements are already projected in the period to 2020 in the *WEO 2000* Reference Scenario. There is real scope for further gains beyond 2020, boosting coal's already important cost advantages over competing fuels. But the nature of coal mining and the maturity of the industry mean that further major cost reductions through breakthrough technologies are unlikely.

Where conditions are economically attractive for new investment, there is no shortage of unexploited supply opportunities. The open and competitive nature of the coal supply chain and the steady growth of international coal trade (in absolute if not relative terms) mean that these opportunities could be readily exploited. Prices could remain highly competitive, especially if oil and gas prices rise in the long term, although coal may be penalised by its higher carbon content.

Technological Responses to Environmental Concerns

Coal's advantages from the point of view of cost and energy security over other energy sources may be eclipsed by the need for coal to satisfy new environmental standards. The long-term prospects for coal may well depend, in particular, on developments in coal-combustion technology that reduce or eliminate carbon emissions or in carbon-sequestration technologies. Coal currently emits twice as much CO_2 per kWh as natural gas in power generation.[4] In addition, costly investments are needed to reduce SOx, NOx, and particulate emissions. These disadvantages have contributed to a growing preference for natural gas by power companies that have to meet increasingly stringent environmental regulations.

Clean Coal Technologies (CCTs) will, therefore, play a vital role in the long-term prospects for coal supply. The current generation of CCTs does not achieve environmental performance that would allow coal to compete effectively in a carbon-constrained world. Not even the most cost-effective versions are commercially viable yet. One of the most promising

4. The difference is less when calculated on a full fuel life-cycle basis.

CCT developments is Integrated Gasification Combined Cycle (IGCC) power generation, which is currently under development in Europe, the United States and Japan. IGCC systems may reach thermal efficiencies above 50%, compared with 33% to 40% achieved by conventional sub-critical plants. They also produce significantly lower emissions of SOx, NOx and particulates. Other advanced cycles are also under consideration, but are at a less advanced stage of development. Hybrid Combined Cycles, for example, combine the best features of coal gasification and combustion technologies in a two-stage process.

Renewable Energy Sources

Beyond 2020, renewable energy is likely to play an increasingly important role in global energy supply. The resource base is vast and, as the term denotes, renewable energy is practically inexhaustible. The environmental impact of renewables' production and use will, in certain cases, favour their market development. Demand for electricity will continue to rise beyond 2020 along with rising incomes and population increases. In the OECD countries, the rate of growth will slow but the rate of retirement of existing capacity will accelerate. These two factors will create significant opportunities for renewable energy to penetrate the power sector. How rapidly it does so will depend on its cost relative to other energy resources. Technological innovation and government policies, especially in relation to carbon emissions, will be the critical factors in this respect.

Developments in Policy and Cost

The promotion of renewable energy will remain a key component of government strategies to achieve sustainable-development objectives. Policies to reduce greenhouse-gas emissions, in particular, will continue to encourage and promote the use of renewable energy. The role of renewable energy in enhancing security of supply may also grow in importance.

Renewable energy will probably remain a relatively costly supply option for power generation up to 2020 in the absence of a sizable carbon penalty. Costs are expected to decline over this period, but not enough to make renewable energy competitive generally with other sources. It is likely that improvements in cost performance will continue for many existing renewable-energy technologies beyond 2020. The timing and the amount of these cost reductions are, however, highly uncertain.

Long-Term Renewable Technology Prospects

The long-term use of renewable energy will depend on technological advances that will bring cost reductions and allow for better integration of these sources into the energy system. Up to 2020, the supply of renewable energy will remain concentrated in OECD countries. In the longer-term, renewables use is likely to become more widespread in developing countries, especially if they establish their own manufacturing capacity.

With increased productivity, energy crops could also provide a low-cost fuel for producing **bioenergy**. However, their long-term development will depend on the availability of land and water, and competition from other uses, especially producing food. Advanced technologies, such as biomass gasification and pyrolysis, could boost the use of bioenergy in heat and electricity production. Bioenergy could also power fuel cells. If these technologies become cost-effective, bioenergy could emerge as a significant energy source particularly where fuel is cheap. Biofuels may become more important in the transportation sector if their production cost is dramatically reduced. The development of technologies that can use cheaper feedstocks could lower the cost of fuel production substantially.

Wind-power production holds promise for continuous growth beyond 2020. Growth in the next two decades is likely to be concentrated in a few regions. Beyond 2020, growth is likely to spread to more countries, notably in the developing world. China, for example, has a wind-energy potential of about 250 GW, which could meet a large share of the country's rising electricity demand. Technological advances that improve the performance of wind turbines may allow less windy onshore sites to be developed. Lower capital costs, reduced maintenance requirements and improved corrosion resistance could boost the development of offshore wind farms. Integrating larger amounts of wind-turbine capacity into networks may require the development of cost-effective **energy storage** technologies.

Hydropower resources will also continue to be used. Although hydroelectricity technology is mature, further advances are possible, particularly for small facilities. Advances in turbine technology such as the use of variable-speed turbines and submersible-turbo generators would bring further cost reductions. Innovative turbine designs could also reduce the environmental impact of hydropower on fish populations.

Further research in the area of hot dry rock **geothermal** technology could lead to further development of the world's geothermal resources. Hot dry rock resources are more widespread than hydrothermal resources and offer the greatest potential for geothermal energy. Increasing well production is the key to reducing costs. In the very long term, the exploitation of the geothermal energy contained in magma may be possible. Magma chambers contain large amounts of energy, but the technical and commercial feasibility of exploiting them has not yet been demonstrated.

Solar energy could become an attractive option for heat and power production in buildings, if the cost of producing energy through solar power continues to fall substantially. The use of photovoltaics (PV) in buildings is likely to continue to expand, both in grid-connected applications and in rural electrification projects. The integration of PV cells directly in the shell of buildings could reduce overall costs substantially. Cost improvements in concentrating solar heat could offer opportunities for larger-scale development of these technologies. Passive solar designs can provide heating and cooling in buildings.

The cost-competitiveness of ocean energy has yet to be demonstrated. Continuous research involving the performance and reliability of ocean technology could eventually bring cost reductions. This form of renewable energy could provide energy for many developing countries, since much of the potential is located in tropical regions.

Nuclear Power

Uranium Resources

The uranium resource base is plentiful. Current estimates show that uranium reserves recoverable at a cost of $130 per kilogramme or less are equivalent to 250 years of current consumption. This estimate does *not* include the use of uranium stockpiles, reprocessing of fuel from existing reactors, fuel produced in breeder reactors or uranium from low-concentration sources such as sedimentary phosphates.

Up to 2020 and possibly for some time beyond, demand for uranium will be met by low-cost reserves. Long-term increases in nuclear electricity generation will require the development of more costly reserves. New mining techniques could help lower production costs. In any case, the economics of nuclear-power production will not be greatly affected, as fuel costs represent a small proportion of total costs.

Lead times to bring major projects into operation are typically between eight and ten years from discovery to start of production, not including the time needed for environmental reviews. Given the time needed for exploration, any significant increase in production is not likely before 2015 or 2020. Over-reliance on the diminishing secondary supply could lead to a supply shortfall beyond 2020 unless early investment in primary production is forthcoming.

Technology and Production Costs

Technological developments in the nuclear-energy sector focus on ways to reduce the use of uranium, either through increasing the efficiency of its use or through reprocessing. Technology also seeks ways to achieve economic competitiveness with other ways of generating electricity, especially natural gas combined-cycle plants. Reprocessing is a currently available technology, which could supply large uranium requirements in the long-term.

Other technologies under development that could reduce natural uranium requirements include tandem cycle reactors such as the PWR-Candu concept and new enrichment technologies, namely the Atomic Vapour Laser Isotope Separation and the Molecular Laser Isotope Separation enrichment technologies. Most of the research into these new technologies is taking place in France, Japan, South Africa, the United Kingdom and the United States.

Relative to other energy sources, current nuclear power plant designs have very high capital costs per MW. Operating and maintenance costs are also higher. These costs are not fully offset by the relatively low fuel cost of nuclear power plants. No country has a complete concept of the facilities and operations that will be necessary for decommissioning and waste disposal, thus there is considerable uncertainty in any cost estimate for future projects.

Specific goals of new plant designs are to reduce construction cost, construction time, operating and maintenance costs and fuel-cycle costs, while improving operating safety. Approaches to achieving these goals include:[5]

- reducing the number of components in the primary and secondary system, to lower capital and operation costs.

5. These and other approaches are discussed in the *Three Agency Study*, a joint undertaking by the IEA, the OECD Nuclear Energy Agency and the International Atomic Energy Agency, IEA (2001). It evaluates twelve new reactor designs in terms of safety, economic competitiveness, proliferation resistance, waste management, efficiency of resource use and flexibility of application.

- using factory assembly and modularisation, to reduce construction costs and schedules.
- reducing the reactor size to 300 MW or less, to reduce the cost of the generating unit and shorten the construction schedule.
- simplifying and reducing the cost of all safety systems and processes, ranging from hardware systems to inspection and testing.
- achieving waste management goals, such as using thorium as a major component of the reactor fuel and reducing the specific volumes of low- and medium-level wastes.

One new reactor technology that is attracting a great deal of interest is the high-temperature gas-cooled reactor. Higher operating temperatures increase the amount of energy the system can convert to electricity. Proponents of this technology claim that it is safer and quicker to build than existing reactor designs. It also creates less spent fuel and can be built on a smaller scale. An international consortium is developing a prototype reactor of this kind, the pebble bed modular reactor (PBMR). A 110 MW demonstration plant at Koeberg near Cape Town, South Africa is planned.

Nuclear fusion, in which energy is produced from the reaction between isotopes of hydrogen deuterium and tritium, may be a longer-term option. Eventually, reactions involving deuterium only or deuterium and helium may be used. Deuterium is abundant, as it can be extracted from water. Tritium does not occur naturally but can be manufactured from lithium, which is plentiful in the earth's crust. Extensive R&D by several countries has so far yielded disappointing results and fusion technology is unlikely to be commercialised until 2050 at the earliest.

Policy Considerations

The future of nuclear power will be influenced greatly by public attitudes and government policy intervention, and therefore its role in the long term is very uncertain. Some governments may seek to introduce or expand the use of nuclear power in their countries on the grounds of emission reductions and fuel diversification. Other countries will abandon it or continue to oppose it if they consider that these advantages do not offset the public concerns that the use of nuclear power raises. Most of today's nuclear plants will reach the end of their life some time beyond 2020, unless closed down prematurely. Policies about how to replace this existing capacity will be of crucial importance to the energy-supply picture after 2020.

Cross-Cutting Technologies

A number of technologies under consideration or active development would exploit energy from several different sources. Hydrogen-based technologies are the main focus of current research and development on cross-cutting supply technologies. They offer the prospect of large-scale energy production with minimal environmental impact. Carbon sequestration or storage technologies deployed in association with fossil-fuel production or combustion could also have a profound impact on the long-term prospects for energy supply.

Hydrogen Technologies

Some analysts believe that hydrogen will be the basic form of energy that will provide power to future societies, replacing natural gas, oil, coal, and electricity. Such a vision is for the very long-term. However, the commercial deployment of some hydrogen technologies, such as fuel cells, is likely to begin soon, although significant market penetration is not expected before 2015-2020.

Hydrogen can, in principal, be obtained from fossil fuels, biomass and water. To produce hydrogen from fossil fuels, the fuel reacts with oxygen or air to produce mainly carbon monoxide and hydrogen. The CO then reacts with steam in a catalytic reactor to give carbon dioxide and more hydrogen. The CO_2 is separated out and stored, and the hydrogen is used as a fuel.

How much carbon is emitted by hydrogen-based systems depends on the fuel input and the production process. Biomass gasification or pyrolysis can produce a fuel gas that is subsequently used to produce hydrogen. Hydrogen can also be produced from water through electrochemical and photochemical processes. If nuclear power or renewable energy is used in these processes, the life cycle CO_2 emissions are close to zero.

Hydrogen as an energy carrier can be used to power fuel cells. These cells are a promising technology as a source of electricity and heat for buildings, and as a power source for electric vehicles. The fuel-cell units currently in operation are generally natural-gas fired, but research efforts are also being directed at the integration of other fuel sources, such as gasified coal, with fuel-cell plant.

Carbon Sequestration Technologies

All power-generation systems fired by fossil fuels can in principle be combined with techniques that capture CO_2 from exhaust gases and store it in ocean depths or geological formations. Carbon-capture technologies deployed in power generation include solvent scrubbing, cryogenics, gas-separation membranes and adsorption. Such technologies may also be applied to other combustion sources, although they would be much less economic for small-scale sources.

Oceans represent the largest potential sinks for the disposal of man-made CO_2 emissions. They contain large quantities of CO_2, about 50 times as much as the atmosphere, mostly in the form of bicarbonate. There are rapid natural interchanges between the atmosphere and the surface layers of the oceans, but the interchanges between the surface layers and the deep ocean are much slower. Thus, if CO_2 were injected into the deep ocean, it may take a very long time to return to the atmosphere. But the environmental effects of ocean storage, such as changes in the pH of the water, are still little understood.

Depleted oil and gas reservoirs have several features that make them attractive for CO_2 storage. The geology of these reservoirs is well known and they are proven traps because they have held hydrocarbons for millions of years. Their exploration costs are low, and some of the hydrocarbon-production equipment can be used for handling and injecting the CO_2. Other geological formations that can be used for the disposal of CO_2 include deep saline reservoirs, very deep coal beds and underground caverns.

The costs of carbon capture and disposal are very uncertain. Recent analysis by the IEA Greenhouse R&D Programme suggests that the total cost might fall in the range of $40 to $60 per tonne of CO_2 stored, of which transport (assuming a distance of 300 km) and storage amount to around $8 per tonne.[6] All the options for capturing CO_2 require extra energy, thus reducing the overall efficiency of combustion, typically by ten per centage points. In power generation, costs are expected to be higher for existing stations than for new ones. Even under optimal conditions, losses and costs related to CO_2 capture increase generation costs by at least 2¢/kWh.

The energy industry will decide the direction of investment in developing and deploying carbon-sequestration, hydrogen and other advanced technologies. But those decisions will be strongly influenced by government actions, including pricing and taxation policies and direct funding of R&D. Collaboration between governments will be critical to mobilising the investment and expertise needed to make technology breakthroughs.

6. IEA Greenhouse R&D Programme status report (www.ieagreen.org.uk/removal.htm).

APPENDIX
REGIONAL DEFINITIONS

OECD Europe

OECD Europe comprises the following countries: Austria, Belgium, Czech Republic, Denmark, Finland, France, Germany, Greece, Hungary, Iceland, Ireland, Italy, Luxembourg, Netherlands, Norway, Poland, Portugal, Spain, Sweden, Switzerland, Turkey and the United Kingdom.

OECD North America

OECD North America consists of the United States of America and Canada.

OECD Pacific

OECD Pacific includes Japan, Australia and New Zealand.

Transition Economies

The transition economies include the following countries: Albania, Armenia, Azerbaijan, Belarus, Bosnia-Herzegovina, Bulgaria, Croatia, Estonia, Federal Republic of Yugoslavia, Former Yugoslav Republic of Macedonia, Georgia, Kazakhstan, Kyrgyzstan, Latvia, Lithuania, Moldova, Romania, Russia, Slovak Republic, Slovenia, Tajikistan, Turkmenistan, Ukraine and Uzbekistan. For statistical reasons, this region also includes Cyprus, Gibraltar and Malta.

China

China refers to the People's Republic of China, including Hong Kong.

East Asia

East Asia includes the following countries: Afganistan, Bhutan, Brunei, Chinese Taipei, Fiji, French Polynesia, Indonesia, Kiribati, Democratic People's Republic of Korea, Republic of Korea, Malaysia, Maldives, Myanmar, New Caledonia, Papua New Guinea, Philippines, Samoa, Singapore, Solomon Islands, Thailand, Vietnam and Vanuatu.

South Asia

South Asia includes India, Pakistan, Bangladesh, Sri Lanka and Nepal.

Latin America

Latin America includes the following countries: Argentina, Bolivia, Brazil, Chile, Colombia, Costa Rica, Cuba, Dominican Republic, El Salvador, Ecuador, Guatemala, Haiti, Honduras, Jamaica, Mexico, Netherlands Antilles, Nicaragua, Panama, Paraguay, Peru, Trinidad/Tobago, Uruguay, Venezuela, Antigua and Barbuda, Bahamas, Barbados, Belize, Bermuda, Dominica, French Guiana, Grenada, Guadeloupe, Guyana, Martinique, St. Kitts-Nevis-Anguilla, Saint Lucia, St. Vincent-Grenadines and Surinam.

Africa

Africa comprises Algeria, Angola, Benin, Botswana, Burkina Faso, Burundi, Cameroon, Cape Verde, Central African Republic, Chad, Congo, Democratic Republic of Congo, Cote d' Ivoire, Djibouti, Egypt, Equatorial Guinea, Eritrea, Ethiopia, Gambia, Gabon, Ghana, Guinea, Guinea-Bissau, Kenya, Lesotho, Liberia, Libya, Madagascar, Malawi, Mali, Mauritania, Mauritious, Morocco, Mozambique, Niger, Nigeria, Rwanda, Sao Tome and Principe, Senegal, Seychelles, Sierra Leone, Somalia, South Africa, Sudan, Swaziland, United Republic of Tanzania, Togo, Tunisia, Uganda, Zambia and Zimbabwe.

Middle East

The Middle East region is defined as Bahrain, Iran, Iraq, Israel, Jordan, Kuwait, Lebanon, Oman, Qatar, Saudi Arabia, Syria, United Arab Emirates and Yemen. It includes the neutral zone.

The groupings listed below are also referred to in the text.

European Union

Austria, Belgium, Denmark, Finland, France, Germany, Greece, Ireland, Italy, Luxembourg, Netherlands, Portugal, Spain, Sweden and United Kingdom.

Organisation for Petroleum Exporting Countries

Algeria, Indonesia, Iran, Iraq, Kuwait, Libya, Nigeria, Qatar, Saudi Arabia, United Arab Emirates and Venezuela.

Asia-Pacific Economic Co-operation

Australia, Brunei Darussalam, Canada, Chile, China, Hong Kong, Indonesia, Japan, Korea, Malaysia, Mexico, New Zealand, Papua New Guinea, Peru, Philippines, Russia, Singapore, Chinese Taipei, Thailand, United States of America, Vietnam.

Gulf Cooperation Council

Bahrain, Kuwait, Oman, Qatar, Saudi Arabia and the United Arab Emirates.

Mercosur

Argentina, Brazil, Uruguay, Paraguay (Chile and Bolivia are associated members)

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